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November 23, 2012

Dana Rzeznik
Permit Engineer
U.S. Environmental Protection Agency Region V

Permit Application No: IL-115-6A-0001

Subject: Second Request for Information Regarding Archer Daniels Midland (ADM) Well CCS#2, United States Environmental Protection Agency Underground Injection Control (UIC) Permit Application #IL-115-6A-0001

Dear Ms. Rzeznik:

Enclosed is the ADM response to the United States Environmental Protection Agency's (Region V) request for additional information regarding Archer Daniels Midland Company's USEPA UIC VI Permit Application #IL-115-6A-0001. The following documents are enclosed:

1. Summary of Response Action
2. Section 3B: Verification Well Design and Construction Data
3. Section 4: Operation Program and Surface Facilities
4. Section 6A: Injection Well Monitoring, Integrity Testing, and Contingency Plan
5. Section 6B: Verification Well Monitoring, Integrity Testing, and Contingency Plan
6. Section 8A: Injection Well Plugging & Abandonment Procedures
7. Section 8B: Verification Well Plugging & Abandonment Procedures
8. Section 8C: Geophysical Monitoring Well Plugging & Abandonment Procedures
9. Appendix E: Material Analysis Plan
10. Appendix F1: Groundwater Monitoring Plan for Quaternary and Shallow Pennsylvanian Strata
11. Appendix F2: Groundwater Monitoring Plan for the St. Peter Sandstone (lowermost USDW)
12. Appendix F3: Groundwater Monitoring Plan for Ironton-Galesville (first permeable saline unit above the primary seal)
13. Appendix F4: Groundwater Monitoring Plan for the Mt. Simon Sandstone (the injectate storage reservoir)
14. Appendix N: Plugging and Abandonment Plan supporting Information
15. Permit Application Reference Materials

Let me know if you have any questions about this matter.

Sincerely,

S McDonald

Scott MCDONALD
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Item #	Section	Subsection	Topic	Notes/Deficiencies	Resolution
1	3	None	Injection, Verification and Geophysical Wells Design and Construction	Provide references for API well construction standards	Included API Standards for Well Construction
2	4	None	Operation Program and Surface Facility	Please provide the composition of the annulus fluid.	Provided annulus fluid composition in Section 4.1.9 Casing/Tubing Annulus Pressure, Average and Maximum.
3	6	6A.1.2	Analysis Parameters	Please provide rational used to select the parameters to be analyzed in Appendix E. Please address the Corrosivity and toxicity of the injectate	1) Provided rationale for selecting the analytical parameters in section 6A.1.2 - Analysis Parameters 2) Addressed the Corrosivity in section 6A.1.2.1 - CO2 Corrosivity 3) Addressed the toxicity in section 6A.1.2.2 - CO2 Toxicity 4) Added CO2 MSDS in Appendix E.
4	6	6A.2	Monitoring Program	Please provide more specific information to "other zones above the caprock, and the shallow groundwater zones" is needed as the geologic stratigraphy of the site is known. The type of monitoring data should be specified to validate modeling techniques used in predicting the distribution of carbon dioxide	Included a comprehensive description of the monitoring program which focuses on ensuring that the subsurface zones above the confining zone are not compromised by the injection and storage of CO2 within the Mt. Simon Sandstone. The subsurface monitoring program focuses on four zones: 1. Pleistocene and Pennsylvanian sands – the source of local drinking water. 2. The St. Peter Sandstone – the lowermost underground source of drinking water. 3. The Ironton-Galesville Sandstone – the zone above the confining Eau Claire cap rock. 4. The Mt. Simon Sandstone – the injection and storage zone. Appendices F1-F4 describes the groundwater monitoring program for each zone.

Item #	Section	Subsection	Topic	Notes/Deficiencies	Resolution
5	6	6A.2.1 & 6A.2.2	Recording Devices & Control and Alarm System for the Well Monitoring and Maintenance	Please specify methods to be used or reference appropriate sections for more detailed information about the monitoring methods and systems	Included a comprehensive description of the monitoring program which focuses on ensuring that the subsurface zones above the confining zone are not compromised by the injection and storage of CO2 within the Mt. Simon Sandstone. The subsurface monitoring program focuses on four zones: 1. Pleistocene and Pennsylvanian sands – the source of local drinking water. 2. The St. Peter Sandstone – the lowermost underground source of drinking water. 3. The Ironton-Galesville Sandstone – the zone above the confining Eau Claire cap rock. 4. The Mt. Simon Sandstone – the injection and storage zone. Appendices F1-F4 describes the groundwater monitoring program for each zone.
6	6	6A.2.5	Tracking Extent and Pressure of CO2 plume	Please specify the type of acoustic measurements and provide reference that the acoustic methods could provide credible results in tracking the plume. Please specify the type of seismic survey to be used.	The proposed methods for Plume and Pressure-Front Tracking for the IL-ICCS project include direct pressure monitoring, reservoir saturation measurements (RST) using pulsed neutron cased hole logging technology, and indirect geophysical monitoring via the use of seismic surveys. Included references for logging technology and for seismic surveys.
7	6	6A.6	Reporting Requirements	In the discussion of semiannual reports under monthly values, please change ii. Flow rate and volume to Flow rate and mass.	Made appropriate change to page 6A-31
8	6	6B.3.1	Continuous Monitoring of Annular Pressure	please explain how the "more than 100 feet" was selected.	Revised description of monitoring set points and provided rationale.

Item #	Section	Subsection	Topic	Notes/Deficiencies	Resolution
9	6	6B.3.1	Continuous Monitoring of Annular Pressure	Could not locate figure 6 - please provide copy.	Figure 6 should have been labeled Figure 6B-1. An example of the pressure monitoring data to be provided is included on Figure 6B-1 "Example Field Log Form for Manual Verification Well Gauge Readings".
10	6	None	Groundwater Monitoring Program	The groundwater monitoring program terminated in the Pennsylvanian……	Included a comprehensive description of the monitoring program which focuses on ensuring that the subsurface zones above the confining zone are not compromised by the injection and storage of CO2 within the Mt. Simon Sandstone. The subsurface monitoring program focuses on four zones: 1. Pleistocene and Pennsylvanian sands – the source of local drinking water. 2. The St. Peter Sandstone – the lowermost underground source of drinking water. 3. The Ironton-Galesville Sandstone – the zone above the confining Eau Claire cap rock. 4. The Mt. Simon Sandstone – the injection and storage zone. Appendices F1-F4 describes the groundwater monitoring program for each zone.
11	7	None	injection Fluid characteristics	No Comments	No changes made
12	8	8A	Injection Well Plugging and Abandonment	With the proposed number of sack of cement used for Plug#1 through #14 the calculated……	Revised section to include excess cement and cost estimate for the plugging and abandonment. Third party cost estimate to be provided in an Appendix N.
13	8	8B	Verification Well Plugging and Abandonment	With the proposed number of sack of cement used for Plug#1 through #14 the calculated……	Revised section to include excess cement and cost estimate for the plugging and abandonment. Third party cost estimate to be provided in an Appendix N.

Item #	Section	Subsection	Topic	Notes/Deficiencies	Resolution
14	8	8C	Geophysical Monitoring Well Plugging and Abandonment	Please provide a Plugging and Abandonment plan for the Geophysical Monitoring Well	Revised section to include excess cement and cost estimate for the plugging and abandonment. Third party cost estimate to be provided in an Appendix N.
15	All	All	General Comment	Please provide all reference documents.	All reference documents provided to the agency.

SECTION 3B – VERIFICATION WELL DESIGN AND CONSTRUCTION DATA

3B.1 Well Depth

The well design for Verification Well #2 (VW#2) will be to drill up to 150 feet into the granite basement in order to define the base of the Mt. Simon with open-hole and cased hole well logs. Based on the CCS#1 injection well completion report (Frommelt, 2010), the well depth is likely 7,250 ft and the casing and cementing program is designed for this depth. Actual well depth will be supplied in the completion report.

For permitting purposes, a well depth of up to 7,500 ft or up to 150 ft into the Precambrian granite basement is requested to account for any unforeseen variations Eau Claire or Mt. Simon thickness or elevation.

3B.2 Anticipated Fracturing Pressure

As reported in the CCS#1 completion report (Frommelt, 2010), the fracture pressure of the Mt. Simon was established to be 0.715 psi/ft. Fracture pressure of the Eau Claire Formation above the Mt. Simon was estimated from four "mini-frac" tests (reference Section 2.5.3.2). The fracture pressure from these four tests ranged from 5,078 to 5,324 psig, corresponding to a fracture gradient ranging from 0.93 to 0.98 psi/ft in the Eau Claire shale.

3B.3 Static Water Level and Type of Fluid

The CCS#1 well data suggests that the top of the Mt. Simon will occur at about 5,500 ft depth. The fluid in the Mt. Simon is hyper-saline brine with a median calculated TDS of ~197,000 mg/L (reference Section 2.4.4.5). Sodium and chloride are the predominant ions. A Mt. Simon pressure gradient of 0.455 psi/ft was measured in the CCS#1 injection well (reference Section 2.4.4.2), which resulted in the static fluid level occurring 220 ft below ground level. Using this pressure gradient, the pressure at the top of the Mt. Simon should be approximately 2,500 psi. The actual pressure and static level will be determined after the well is fully cased and perforated.

3B.4 Expected Service Life of Well

The expected service life of the well is projected to be at least 30 years. Because of the CO_2 resistant cement and metallurgy of the casing used in this well, the life of this well could be much longer if sequestration demands are present.

3B.5 Verification Well Completion

The verification well will be cased to total depth (TD) and each string will be cemented to prevent movement of fluid along the borehole and outside of the casings. The lower portion of the long string will be cemented with a CO_2-resistant EverCRETE cementing system. The CO_2 resistant cement will cover the entire open hole section from TD and be placed from total depth through the Eau Claire Formation and approximately 500 feet back into the intermediate casing. A conventional blend lead slurry will pumped ahead of the CO_2 resistant cement to fill the annular space between the intermediate and long string casings. One intermediate casing string is planned; it will be set after drilling into the calcareous section of the upper Eau Claire Formation and will be cemented to surface. The well will be perforated at discrete intervals in the Mt. Simon (Table 3B-1). No casing perforations will be placed above the top of the Mt. Simon formation.

In VW#2, a multi-zone monitoring system will be installed in the wellbore with packers straddling and isolating each set of perforations.

Results of the data obtained and an anaylsis of pressure data will be submitted in the well completion report. The information will also include a report of measured hydrostatic gradients between the various perforated levels in the Mt. Simon Sandstone.

Perforation Depths. The VW#2 perforations are expected to be placed at five intervals in the Mt. Simon Sandstone in an attempt to more clearly understand how the injected CO_2 moves through the reservoir. Pressure monitoring in these zones will be used to measure effects of injected CO_2. The three uppermost perforation intervals will be configured with an intelligent completion (IC) system with interval control valves. Permanent downhole gauges will be installed to monitor individual pressures for each of the five perforated intervals.

Table 3B-1 below lists an estimate of perforation depths for pressure monitoring. Depths are based on the well logs from the existing wells in the area; final perforations will likely change and will be reported in the well completion report.

Table 3B-1. Perforation location table. SPF = slots per foot.

Interval	Depth	Formation	Interval / SPF
1	5,560	Mt. Simon	Approx 3 ft interval & 4 Shots per ft
2	5,840	Mt. Simon	Approx 3 ft interval & 4 Shots per ft
3	6,430	Mt. Simon	Approx 3 ft interval & 4 Shots per ft
4	6,720	Mt. Simon	Approx 3 ft interval & 4 Shots per ft
5	6,950	Mt. Simon	Approx 3 ft interval & 4 Shots per ft

Completion Fluid: During the initial completion, when the multi-zone monitoring system is being installed, a completion or kill brine will be used. This brine will be NaCl based with a specific gravity of 1.11 to 1.13 with a hydrostatic gradient of approximately 0.488 psi/ft.

After injection begins, there will be a gradual pressure increase in the Mt. Simon Sandstone. The current reservoir modeling (reference Section 5) suggests that the ultimate pressure increase at VW#2 will be less than 200 psi. During this period of peak pressure, the corresponding gradient is approximately 0.48 psi/ft. This increase in pressure, however, dissipates relatively quickly after injection is ceased. The use of a heavy brine for an annular fluid would be detrimental for any sampling efforts, so the completion fluid will be kept near the specified 9.4 ppg during the original installation. A heavier brine may be placed above the uppermost packer later in the life of the well as required. This can be done by opening a circulating port and then circulating through the port, followed by closing of the circulating port.

3B.6 Schematic or Other Appropriate Drawing of the Subsurface Construction Details of the Well

A schematic showing subsurface details of the verification well are found in Figures 3B-2.

Note: Casing and bit depths may be modified dependent upon actual geologic and borehole conditions encountered during the drilling/completion operation. Final depths will be reported in the well completion report.

3B.7 Well Design and Construction

The subsurface and surface design (casing, cement, and wellhead designs) exceeds minimum requirements to sustain the integrity of the borehole and well, and prevent the verification well from acting as a conduit for the movement of fluids up or down in the wellbore. For reasons such as equipment or supply availability, or changes to the supplemental monitoring program, the final well design will continue to exceed these requirements in terms of strength and CO_2 compatibility.

The wellbore trajectory of each of the deep wells (injection, verification, and geophysical wells) will be tracked. The wells will be drilled to an inclination standard that will eliminate the risk of interception with adjacent wellbores and surveyed at least every 1,000 feet to ensure compliance. Wells are planned to be held to less than 5 degree inclination.

Note that depths given are based on anticipated drilling conditions and estimated depths of formations and are subject to change. Final depths will be reported in the well completion report.

3B.7.1 Wellbore Diameters and Corresponding Depth Intervals

Table 3B-2 summarizes the open hole, drilled hole diameters and depths based on the hole size desired at TD and planned drilling and testing. Setting surface pipe to between 300 - 400 feet is expected to be well below the lowermost USDW so that all shallow groundwater that may potentially be used for domestic or commercial use is protected. The depth of the intermediate string is planned for the upper section of the Eau Claire to reduce the time the drilling mud is in contact with the shallower zones from 350 - 5,300 feet. At this time, routine drilling operations are expected; however, if this changes, intermediate casing may be run at a different interval.

Table 3B-2: Open hole diameters and intervals

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Surface	0 - 350	17 ½	To bedrock
Intermediate	350 – 5,300	12 ¼	To primary seal
Long String	5,300 – 7,250	8 ½	To TD

Note 1: Estimates given based on anticipated drilling conditions and depth of formations;

3B.7.2 Casing

The designed life of this well is for the life of the project and any subsequent monitoring period. The casing will be protected on the outside by the cement sheath and will have limited exposure to well fluids. As a result, all casing strings are designed as carbon steel except for the bottom portion of the long string (from approximately 5300' to TD) where a chrome alloy casing is planned.

Corrosion of carbon steel casing is not expected during the life of this well. However, the potential for corrosion of casing material in the verification well will be addressed by using CO_2-resistant cement and time-lapse formation sigma log monitoring described in Section 6B.3. Should monitoring show that corrosion has become an issue and it will negatively impact zones above the primary seal, a contingency plan will be developed to address the issue, up to and including plugging and abandonment of the well, as per Section 8B.

The current casing design calls for three casing strings as outlined below. The casing strings specified below are listed as minimum performance requirements.

Table 3B-3: Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lbm/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77 °F (BTU/ft.hr.°F)
Surface	0-350	13 ⅜	12.515	54.5	J55	Short	29.02
Intermediate[1]	0-5,300	9 ⅝	8.835	40	N80	Long	29.02
Long[2]	0 – 7,250	5 ½	4.950	17#	N80 + 13CR85	Long or short	31.00 for carbon,13 for Cr13

Note 1: K55 or J55 to 1,200 feet; N80 to 5,300 feet.
Note 2: N80 from surface to 5,300 feet; chrome alloy (e.g., 13Cr80) from 5,300 feet to total depth.

<u>Other Casing</u>
No other casing strings are planned.

3B.7.3 Tubing

The verification well will be completed with a combination of tubing strings. 2 ⅞" API 6.5# production tubing (carbon steel) will be used from surface down to approximately 5,500 ft. The multizone monitoring system will have corrosive resistant tubing components below the uppermost packer. No restrictions smaller than 2.25" will be installed in the entire tubing string. Current plans call for a gas lift to be placed in the tubing at approximately 1,000 ft. If implemented, a stainless steel tubing of 5/8-inch diameter will connect the gas lift valve to a nitrogen reservoir at the surface. This will allow Nitrogen gas to be injected into the production tubing via the gas lift valve to enable purging of the tubing if needed for sampling operations.

3B.7.4 Cement

The casing strings will be cemented as outlined below:

Surface casing will be cemented back to surface; should fallback of more than 30 feet occur, a surface grout job will be performed.

The planned cement interval for the intermediate string is to cement back to surface; the performance standard applied to the intermediate casing will be to have cement into the surface pipe. Should this standard not be achieved a cement bond log and or temperature survey will be run shortly after cementing to locate the actual cement top. After notifying the permitting agency and conferring as to the remediation required, a plan will be developed. The most likely scenario is that the annulus between the surface casing and intermediate casing will be grouted and pressure tested to insure hydraulic isolation. In any event, a Cement Bond Log with radial capability or Ultrasonic Cement Imaging logs will be run prior to running the long string casing.

On the long string the planned cement interval is from TD back to surface; CO_2 resistant cement will be used from TD through the Eau Claire. The performance standard applied to the long string will be to have at least 1,000 feet of cement into the bottom section of the intermediate casing. Should this standard not be achieved, a cement bond log and/or temperature survey will be used to establish the cement top. The permitting agency will be notified immediately and discussions will occur as to the best method to remediate. Options would include grouting, top filling from the surface where cement would be pumped into the annulus until annulus is "topped out", or perforating above the cement top and attempting to circulate cement from the cement top. Perforations would then have to be squeezed off and pressure tested to 1,000 psi with no leak off. In any event, a Cement Bond Log with radial capability or Ultrasonic Cement Imaging logs will be run prior to the well completion.

Note that the cementing programs provided in Table 3B-6 are estimates, and may be adjusted as a result of hole conditions, depths, etc.

Table 3B-6: Cement Specifications for Verification Well #2

Name	Depth Interval (feet)	Type/ Grade	Additives	Quantity (cubic feet)	Circulated to Surface	Thermal Conductivity (BTU/ft.hr. ^{o}F)
Surface	0 - 350	Class A	Accelerator, LCM	425	Yes	0.73
Intermediate	0 - 5,300	Lead : 35:65 LP3:Class A Tail: Class A or H	Extender, antifoam, LCM Dispersant, fluid loss additive	1784 (lead), 316 (tail)	Yes	0.54(lead) 0.74(tail)
Long	0 - 7,250	35/65 Lead; CO_2 resistant tail	Antifoam, dispersant, fluid loss + antisettling (tail)	1176 (lead), 656 (tail)	Yes	0.75

Note 1: Surface casing: +/- 350 sks of Class A + additives. Density: 15.6 ppg, Yield: 1.20 cf/sk, Mix water: 5.23 gal/sk, Excess 75%

Note 2: Intermediate casing: Lead slurry +/- 910 sks of lead 65-35 Cement-Poz, 4% Gell, 10 % BWOW salt, + additives. Density: 12.9 ppg, Yield: 1.96 cf/sk, Mix water: 9.95 gal/sk. Followed by tail slurry: +/- 300 sks of Class A/H + additives. Density: 15.6 – 16.1 ppg, Yield: 1.10 - 1.19 cf/sk, Mix water: 4.97 – 5.234 gal/sk, Excess 30%.

Note 3: Long string casing: Lead slurry: +/- 600 sks cubic ft of 65-35:Cement-Poz + 6% extender + 10% salt BWOW + additives. Density: 12.5 ppg Yield: 1.96 cf/sk Mix water: 10.54 gal/sk; Excess 30% in O.H. and no excess inside intermediate. Followed by tail slurry: +/- 625 sks CO_2 resistant cement + additives. Density: 15.9 ppg, Yield: 1.05 cf/sk, Mix water: 3.012 gal/sk, Excess 30%

CO_2 resistant cement will cover the entire open hole section from TD and be placed approximately 500 feet back into the intermediate casing. Assuming the intermediate casing will be set approximately 50 feet into the Eau Claire, the CO_2 resistant cement will be about 450 feet above the Eau Claire.

Other Casing

There are no plans for additional casing strings at this time; however, depending on actual drilling conditions the well plan may be adjusted to accommodate unplanned events. The permitting agency will be notified prior to any casing additions.

Cementing Techniques, Equipment Positions, and Staging Depths

Casing centralizer design and placement will be perfomed for all casing strings to optimize casing centering and mud removal. Drilling and log data will provide well bore trajectory and hole size information and will be utilized in the design program.

The cement plan incorporates use of a one-stage cementing technique for each string if hole conditions allow. A casing float shoe will be placed on the bottom of the casing string and a float collar placed at the top of the first or second joint of casing above the bottom. A bottom wiper plug will be used to wipe the mud film from the casing ahead of the cement job. The bottom of the casing will be set a few feet off the bottom of the hole. Actual cement pumping and displacement rates will be determined using well specific parameters such as mud properties and hole size learned during the actual drilling process and will utilize wireline surveys, including a caliper log. A custom spacer will be pumped ahead of the cement system to assist in mud removal.

Although single stage cement jobs are planned for all casing strings, information learned during the drilling process (e.g. lost drilling returns) and testing of the open hole (e.g. significant fractures identified via well logs) may lead to a decision to use a two-stage cementing technique on any or all of the strings. The intermediate casing for CCS#1 was performed in a two-stage operation. If a lost circulation zone is encountered in this verification well then the expectation would be that a two stage job would be required. The CCS#1 well's long string was successfully cemented back to surface in a single stage operation, however should a two-stage cement system be required for the long string, the lower cement stage will cover the Mt. Simon and Eau Claire and come up to a few hundred feet above the Eau Claire. A stage cementing tool will be run on the long string casing allowing the second stage or upper section to be cemented after the lower cement stage has reached approximately 500 psi compressive strength. The designed lead system will cover the upper hole section and a small amount of the CO_2-resistant cement may be tailed in and placed across the stage cementing collar. The stage cementing collar will be drilled out and casing integrity test performed.

Section 7.5.4 of this application includes a description of the CO_2-resistant cement. Appendix B has the complete manufacturer's specifications. Table 3B-7 below is the manufactures specifications for the specific density planned for lower portion of the injection casing cement.

Table 3B-7: Manufacturers Specifications for Long String Casing Cement

BHCT (Bottomhole circulating temperature)	40 °C [104 °F]
BHST (Bottomhole static temperature)	50 °C [122 °F]
Specific gravity [lbm/gal]	15.9 ppg
Rheological properties determined with API R1B5 after	
PV (cp) (Plastic Viscosity)	454.623
T_y (lbf/100ft^2) (Yield Point)	28.45
After conditioning at BHCT	
PV (cp)	247.198
T_y (lbf/100ft^2)	28.16
10 second gel strength (lbf/100ft^2)	22
10 minute gel strength (lbf/100ft^2)	25
Then 1 minute stirring gel strength (lbf/100ft^2)	19
Stability	OK no sedimentation
API fluid loss at BHCT	0
Thickening time at BHCT	
30 Bc	1hr, 46 min
70 Bc (unpumpable)	4 hr, 18 min
UCA cell compressive strengths*	
50 psi	18 hr, 29 min
500 psi	21 hr, 07min
24 hour comp. strength psi	1177

Perforation Depths

The verification well perforations are expected to be placed at five intervals in the Mt. Simon Sandstone in an attempt to more clearly understand how the injected CO_2 moves through the reservoir.

Table 3B-1 lists an estimate of perforation depths for pressure monitoring. Depths are based on the well logs from CCS#1 and VW#1; final perforations may change and will be reported in the well completion report.

3B.7.5 Annular Protection System

This section describes the annular protection system which monitors the annular space extending from the uppermost packer to the surface. Further information regarding the monitoring of annular space below the upper most packer can be found in Section 6B.3, Mechanical Integrity Tests During Service Life of Well.

The well will be constructed and operated in such a way to meet Federal requirements of 40 CFR Part 146 UIC Permit Program Subpart H, to establish and maintain mechanical integrity. The surface and intermediate strings will be cemented to surface so there are no open annuli between these strings.

The long string casing will be filled with a brine with a density of 9.4 pounds per gallon. The brine will be present after the casing is installed and during completion of the monitoring system. The reservoir pressure gradient is 0.451 psi/ft (as determined in the CCS#1 well). The annulus will be bled and fluid will be replaced as needed until the entrained air is removed from the annulus. After the initial completion is installed the annulus between the production tubing string and the long string casing above the uppermost packer will be pressure tested to 300 psig for one hour with a maximum leakoff of not more than 3%. During the life of the well this same annulus will be pressure tested to 200 psig on an annual basis, again with a maximum of 3% leakoff allowed.

The annulus between the production tubing and the long string casing will be monitored at the surface for the absence of significant pressure changes (pressure rise due to fluid entering annulus or vacuum due to fluid loss). The uppermost packer will be located above the uppermost perforation expected to be in the lower Potosi Formation, several thousand feet below the lowermost USDW and several hundred feet below the secondary seal of the Maquoketa Formation. The annulus fluid's hydrostatic gradient is greater than the pre-injection pressure of any of the perforated intervals. A change in pressure that exceeds an increase of 100 psi or a vacuum of 203 inches Hg (representing an equivalent fluid change of about 100 feet) can be construed as evidence of loss of integrity and would trigger an investigation. If leakage were to occur during the life of the well and CO_2 laden fluid were to rise past all of the packers then a positive pressure would develop on the annulus due to CO_2 gas being liberated from the fluid as it migrates upward. Similarly, if fluid were lost, then a vacuum would develop. The annular pressure gauge will monitor both conditions.

3B.7.5.1 Annular Space

With regard to the annulus protection system, the annulus of the well is defined as the volume above the uppermost packer and the surface. The space will be the annulus between the production tubing and the 5 ½-inch OD long string casing.

3B.7.5.2 Type of Annular Fluid(s)

The annulus above the upper packer will be filled with a NaCl or equivalent completion brine with a density of approximately 9.4 ppg.

3B.7.5.3 Specific Gravity of Annular Fluid(s)

The annulus between the long string casing and production tubing is expected to contain approximately 9.4 ppg completion fluid. The specific gravity will be approximately 1.11–1.12. Actual densities will depend upon the highest formation gradient encountered. Annular fluid gradient will be greater than the largest encountered fluid gradient.

3B.7.5.4 Type of Additive(s) and Inhibitor(s)

Completion fluid will contain corrosion inhibitors.

3B.7.5.5 Coefficient of Annular Fluid(s)

The well is expected to have a minimum of 0.488 psi/ft gradient (coefficient) in annulus or at least 0.1 ppg over and above normal water specific gravity or psi/ft. on depth of packer placement.

3B.7.5.6 Packer or Fluid Seal

The verification well will be completed using a multi-zone pressure monitoring system . The system contains a series of packers used to isolate discrete intervals within the wellbore. Completion brine or Mt. Simon Sandstone brine will be in the annulus and between all the packers. Above the uppermost packer, the annular space will be filled with a 9.4 ppg completion brine. There will be a dedicated pressure gauge at the wellhead to monitor the casing/tubing annulus.

3B.8 Information on Well Drilling Company Used During Construction

Drilling Firm Information

A drilling contractor has not yet been selected. This decision will be based on rig availability and the final decision of project management regarding procurement. Details about the drilling contractor will be provided in the well completion report.

3B.8.2 Drilling Schedule

The preliminary well construction (drilling & completion) schedule will hinge on the timing of permit availability. Utilization of a single drilling rig to sequentially drill the injection, verification, and geophone wells is aimed towards providing the best consistency and quality of the many services required for drilling wells.

3B.8.3 Drilling Method

A rotary drilling rig will be used. The expected rig will be of a minimum rating to drill to expected depth and handle designed casing loads as well as have the set-back capacity adequate to drill a well to this depth. Blow Out Preventers (BOP) will be used in the unexpected event of an interval or zone having higher pressure than anticipated. The mud system will be designed to maintain overbalanced drilling.

3B.9 Tests and Logs

ADM will provide a schedule for all testing and logging to the permitting agency at least 30 days in advance of conducting the first such tests and/or logs.

3B.9.1 During Drilling

With the exception of the surface pipe interval, each open hole section (prior to setting each casing string) will be logged with multiple suites to characterize the geologic formations (reservoirs and seals). At a minimum, all wireline runs will have resistivity, spontaneous potential (SP), gamma ray (GR) and caliper logs. Sonic and porosity logs additionally will be included on the intermediate and TD run. The TD run will also include magnetic resonance, micro-imaging (dipmeter and fracture ID), formation pressure and rotary cores. Cement imaging logs will be run on the intermediate casing string. A cement evaluation log is not planned on the surface casing if cement is returned to surface with no fallback and if surface casing shoe test is successful. Whole core may also be acquired during drilling.

3B.9.2 During and After Casing Installation

Based on previous analysis and results in the area, stimulation will not be required.

Cement bond logs and/or cement imaging logs will be run on the long string.

Pressure Transient Analysis methods may be used to garner additional permeability information. To obtain the necessary data an injection or pumping test may be performed.

3B.9.3 Demonstration of Mechanical Integrity

Cement and system mechanical integrity will be verified with cement imaging logs with a radial capability (e.g. Schlumberger Slim Cement Mapping Tool (SCMT), UltraSonic Imaging Tool (USIT), etc).

A baseline reservoir saturation tool (RST) and temperature log will be run to be available for comparison with subsequent passes for detailed knowledge of where the injected CO_2 may have moved vertically. The 2 ⅞-inch tubing by 5 ½ inch casing annulus above the uppermost packer will be pressure tested to establish mechanical integrity.

3B.9.4 Copies of the Logs and Tests Listed Above

The logs and tests listed above will be conducted during well construction and copies of these logs will be included in the well completion report provided to the permitting agency.

3B.10 References

Frommelt, D., 2010. Letter to the Illinois Environmental Protection Agency, Subject: CCS Well #1 Completion Report, Archer Daniels Midland Company – UIC Permit UIC-012-ADM, dated May 5, 2010.

Figure 3B-1: Verification Well location diagram.

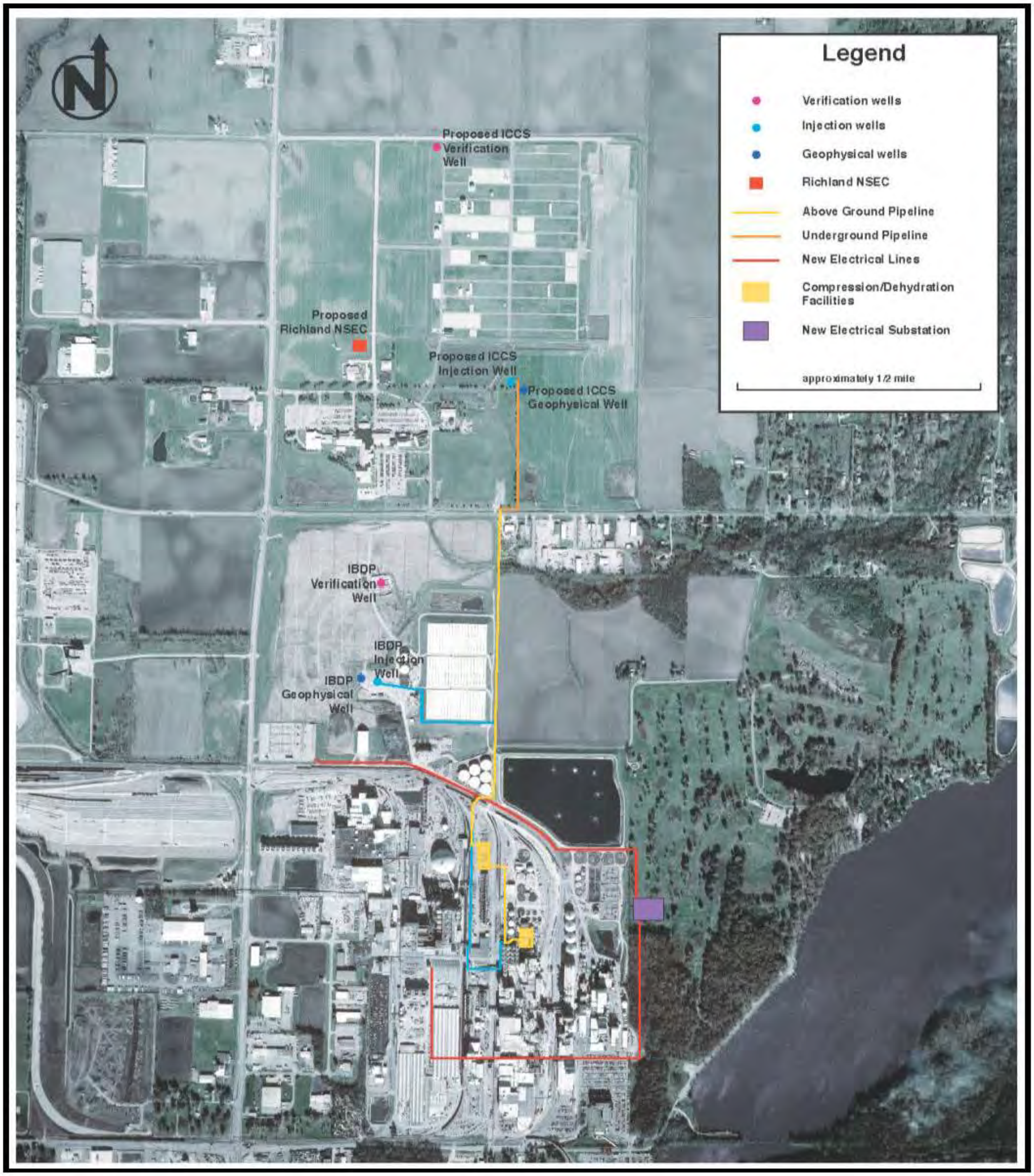
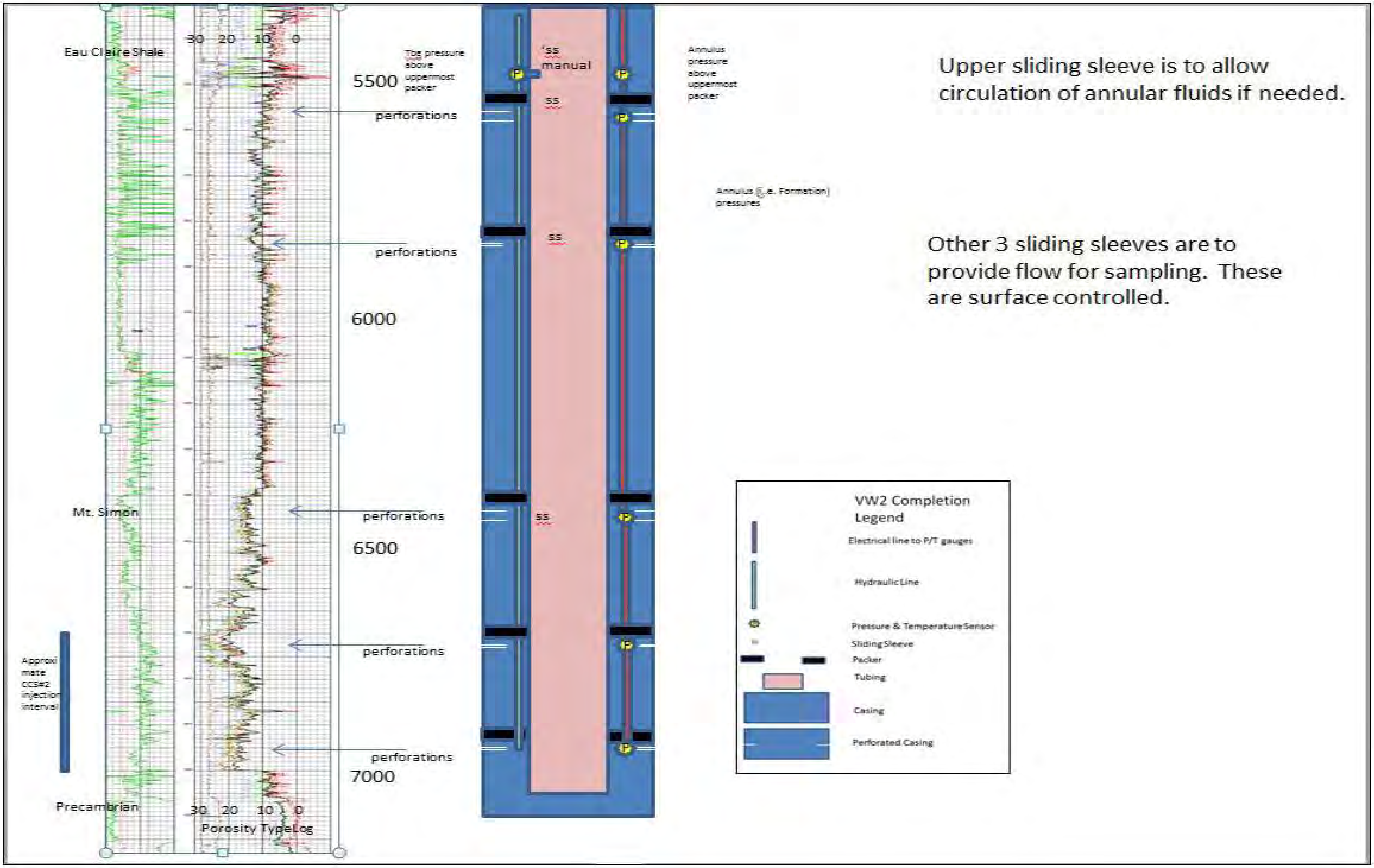


Figure 3B-2: Verification Well Schematic



SECTION 4 - OPERATION PROGRAM AND SURFACE FACILITIES

4.1 Operation Program

4.1.1 Number or Name of Well

The IL-ICCS project injection well will be named CCS #2.

The IL-ICCS project verification well will be named Verification Well #2, and the IL-ICCS project geophysical well will be named Geophysical Monitor Well #2.

The well names are similar (except for use of #2 instead of #1) to the well names used in the Illinois Basin – Decatur Project (IBDP).

4.1.2 Location

Injection well CCS #2 location is as follows:

Section 32, Township 17N, Range 3E of 3rd Principal Meridian.
Latitude: N 39° 53’ 8” (N 39.88577°)
Longitude: W 88° 53’ 19” (W 88.88883°)

4.1.3 Expected Service Life

The expected service life of the well is 30 years. Currently, the operator is planning for a 5-year injection (operational) period. Therefore, if the operator elects to continue injection past the 5-year schedule, the facility could operate an additional 25 years subject to 40 CFR 146.

4.1.4 Injection Rate, Average and Maximum

The compression and dehydration system is designed for a normal operating capacity of 3,000 metric tons (MT) per day with a maximum operating capacity of 3,300 MT per day. A custody transfer flow measurement device will be installed on the CO_2 transmission pipeline between compression and dehydration facility and the injection wellhead. The flow meter will produce a direct reading of total amount of injected CO_2 in units of mass per unit of time.

The average injection rate will be 2,800 MT per day over the project’s 5-year life (average of 2,000 MT per day for the first year and 3,000 MT per day for remaining years). Based on the design of the compression and dehydration equipment, the facility will have a maximum injection capacity of 3,300 MT per day.

Over the life of the project, approximately 4.75 million MT of CO_2 will be injected into the Mt. Simon Sandstone. Current site modeling predicts the CO_2 plume produced from the IL-ICCS project as well as the plume from the nearby IBDP project will be retained within the Mt. Simon

Sandstone. Section 5 of this application contains illustrations generated from the site models. These illustrations show the location and extent of the CO_2 plumes for both projects.

4.1.5 Anticipated Total Number of Injection Wells Required

It is anticipated that one injection well of appropriate design is required for injection of the maximum daily rate of CO_2.

There is another injection well – the IBDP injection well, CCS #1 – operating at the ADM site. This well is currently operating under permit No. UIC-012-ADM, but is not part of the proposed IL-ICCS project.

During this project, ADM plans to operate two injection wells for a period of time (est. 1-year). CCS #1, which is operating under State of Illinois permit, No. UIC-012-ADM, will be injecting CO_2 at an operational capacity of 1,000 MT per day with a maximum capacity of 1,100 MT per day. The location of this well is approximately 1 mile southwest of the proposed IL-ICCS CCS #2 well and the source of CO_2 is the ADM ethanol production facility. The CCS #2 well, for which this application has been prepared, will be supplied with CO_2 from the ADM ethanol production facilities at an initial operational capacity of 2,000 MT per day with a maximum capacity of 2,200 MT per day.

Following completion of the IBDP project's injection period, which is estimated to be the first quarter of 2014, the IL-ICCS project will assume operation of the IBDP compression facility and will increase the project's operational injection capacity by 1,000 MT per day with a maximum capacity of 1,100 MT per day. Thus, the total amount of CO_2 that can be supplied to injection well CCS #2 will be 3,000 MT per day operational capacity with a maximum capacity of 3,300 MT per day.

4.1.6 Number of Injection Zone Monitoring Wells

There are plans to drill and complete one injection zone (Mt. Simon) monitoring well (Verification Well #2) within approximately 3,000 feet north-northwest of the injection well (CCS #2). This well will be drilled to verify the location of the CO_2 within the Mt. Simon. Details regarding the verification well design and construction are included in Section 3B.

A geophysical (geophone) monitoring well (Geophysical Monitor Well #2) will be drilled and completed within 500 feet of the injection well. This well will be drilled in order to provide geophysical monitoring of the CO_2 plume. Details regarding the geophysical well design and construction are included in Section 3C.

A schematic of the injection, verification, and geophysical wells is provided as Figure 4-1. All wells will be drilled and completed prior to CO_2 injection into the CCS #2 well.

4.1.7 Injection Well Operating Hours

The injection well will operate continuously (24 hour per day, 7 days a week, and 365 days per year) during the permit period. The injection rate will vary between 0 and 3,300 MT per day for equipment maintenance, mechanical inspection, and testing subject to § 146.89 and § 146.90.

4.1.8 Injection Pressure, Average and Maximum

The operational injection pressure is estimated to be between 2,100 and 2,300 psi with an estimated maximum injection pressure of 2,380 psi. The higher pressure would be a result of lower Mt. Simon injectivity parameters. These pressure estimates are based on the design surface compression capacity of 3,000 MT per day (3,300 MT per day maximum) and the calculated injectivity of the Mt. Simon Sandstone developed from the IDBP project data using a 0.6435 psi/ft injection gradient (90% of the formation fracture gradient of 0.715 psi/ft).

4.1.9 Casing/Tubing Annulus Pressure, Average and Maximum

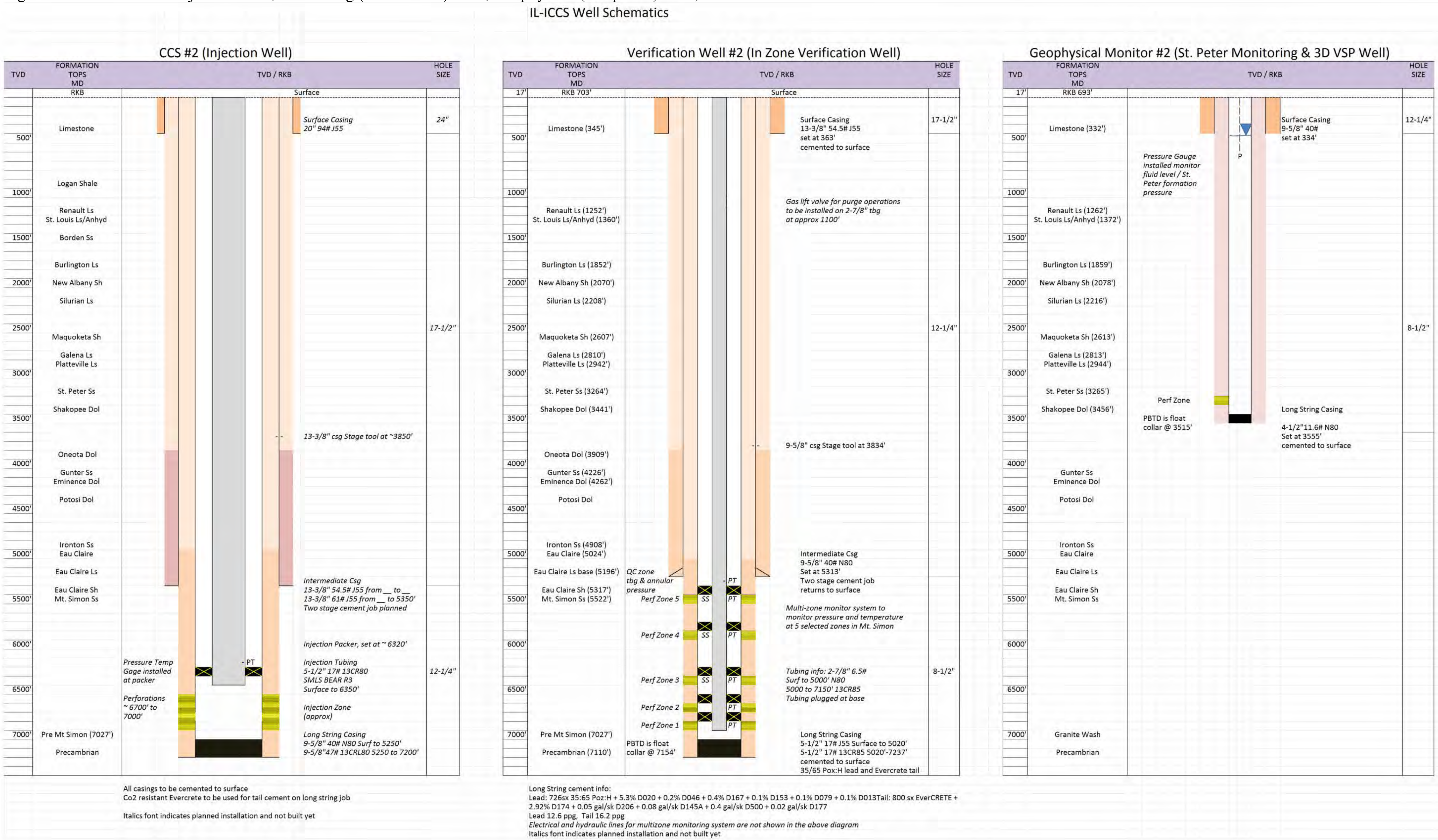
Because the injection tubing will be set in a packer above the injection interval within the Mt. Simon, the casing-tubing annulus space will be isolated from the CO_2 stream. A constant surface annulus pressure of 400 to 500 psig is anticipated during injection. The annular fluid is expected a combination of calcium and sodium brine with corrosion inhibitor and with a density of 10.5 pound per gallon (0.545 psi/ft) and a freezing temperature of negative 26 degrees Farenheit. To build one barrel of solution 32 lbs of salt and 128 lbs of 77-80% Calcium Chloride is added to 32.8 gallons of water. Approximate salt percentages are 8% Nacl-22% Cacl. Corrosion inhibition will be provided by one of the common brine corrosion inhibitors available in the marketplace. The corrosion inhibitors are typically film coating organic compounds (barrier inhibitors) and are added at concentrations of 1-2% depending upon specific product

Barrier inhibitors form a layer on the corroding metal surface, modifying the surface to reduce the apparent corrosion rate. They represent the largest class of inhibitive substance. Absorption type inhibitors are the most common barrier layer inhibitors. In general these organic compounds are adsorbed and form a stable bond is the metal surface. The apparent corrosion rate decreases as surface adsorption is completed. Vapour phase corrosion inhibitor (VPCI) is adsorption type corrosion inhibitors with high passivation properties. These inhibitors form a stable bond with the metallic surface. Generally, they have a high vapour pressure that allows the material to migrate to distant metallic surface. Therefore, VPCI, require no direct contact with the metal surface to be protected. Conversion inhibitors also form barrier layers. They passivate the metallic surface by developing and insoluble metal oxide on the surface. Typical examples of this type of inhibitor are organic phosphates and chromates. (**EVALUATION OF CORROSION INHIBITORS EFFECTIVENESS IN OILFIELD PRODUCTION OPERATIONS** Osokogwu, U, Oghenekaro .E.) Typical of these corrosion inhibitors would be MI-Swaco Conquor 303a, Adomite ASP539D, Tetra CORSAF SF. Product Data Sheets for these are attached to this application.

The average and maximum are anticipated being about the same pressure; however, fluctuations in pressure are anticipated from changes in ambient surface temperature and injection tubing pressure.

All other annulus spaces (one between surface casing and intermediate casing, and one between intermediate casing and long string casing) will have cement to surface. Consequently the pressures of these annular spaces will be at atmospheric pressure.

Figure 4-1. Schematic of Injection Well, Monitoring (Verification) Well, Geophysical (Geophone) Well,



4.2 Surface Facilities

4.2.1 Injection Fluid Storage

There will be no intermediate storage of injection fluid. The CO_2 for this project is produced continuously from the ethanol production facility and will be vented to the atmosphere if the injection well is not operational.

4.2.2 Holding Tanks and Flow Lines

There will be no holding tanks for the injection fluid. The flow line from the compression and dehydration facility to the injection site is estimated to be an 8-inch diameter schedule 120 carbon steel pipe. The final pipe size, schedule, and material of construction will be determined upon completion of the final facility engineering design and reservoir modeling.

4.2.3 Process Flow Diagrams and Process Description

The front end engineering design (FEED) has been completed for the collection, compression, and dehydration, and transmission facility. The collection, compression, and dehydration facility has a design capacity of 2,000 MT per day with a maximum capacity of 2,200 MT per day. The transmission facility (8" pipeline to the injection well) has a design capacity of 3,000 MT per day with a maximum capacity of 3,300 MT per day. The process flow diagrams (PFDs) for this unit shown are shown in Figures 4-2 through 4-7. Piping & instrument diagrams (P&IDs), issued for engineering approval, are provided in Appendix C.

CO_2 is produced during ethanol fermentation and is vented from the fermentation vessels and sent to an existing wet gas scrubber (not shown in figures). In the wet gas scrubber, water is used to remove any entrained ethanol and other water soluble contaminants from this stream. Next, the water saturated CO_2 exits the top of the scrubber at 15 psia, and 100°F. This is the point at which the design basis for this facility was developed.

Illustrated in Figure 4-2, the gas leaving the scrubber passes through a separator drum (TK-501/502) to remove any condensed or entrained free water. Next the CO_2 is compressed with a centrifugal blower (BL-501/502) to 32 psia. Because of the compression ratio, the gas temperature increases to above 200°F. Next the hot compressed CO_2 is cooled to 95°F by passing through the compressor after cooler (HE-501). The blower after cooler separator (TK-503) removes any water that condenses during compression and cooling.

After free water removal, the gas stream is divided into four streams; each feeding a four-stage reciprocating compressors which operate in parallel. Each compressor is designed for an operational capacity of 500 MT per day with a maximum capacity of 550 MT per day. These compressors (K-600, K-700, K800, and K-900) are shown in Figure 4-3 through 4-6.

Each figure shows the 4 stages of compression and represents one machine. The compressors are six throw (6 cylinder) machines with two (2) cylinders used for the first stage of compression, two (2) cylinders for the second stage of compression, one (1) cylinder for the third stage of compression, and one (1) cylinder for the fourth stage of compression.

In the first stage (K-601/701/801/901), the CO_2 is compressed to 75 psia, with a discharge temperature of 293°F. After this stage, the gas is cooled by the interstage cooler (HE-601/701/801/901) to 95°F, and sent to an interstage separator (VS-602/702/802/902) to remove any free water condensed during compression and cooling.

From the separator, the gas flows to the second compression stage (K-602/702/802/902). In this stage the CO_2 stream is compressed to 249 psia with a discharge temperature of 313°F. Next, the compressor discharge stream is cooled to 95°F in the second interstage cooler (HE-602/702/802/902) and sent through a separator (VS-603/703/803/903) to remove any condensed water.

From the separator, the gas flows to the compressor's third stage (K-603/703/803/903), where it is compressed to 598 psia and 253°F. As with previous compression stages; the gas is cooled to 95°F in the interstage cooler (HE-603/703/803/903). At this point, 95% of the water entering the process has been removed through compression and cooling.

After the third stage of compression, the CO_2 stream contains approximately 1300 ppmwt H_2O. Because this exceeds the recommended water content for subsurface injection, the four streams are recombined to be sent to the glycol dehydration skid. This operation is represented in Figure 4-7.

The design basis for the dehydration unit is for the unit to dehydrate the CO_2 stream so that the exiting stream contains no more than 30 lbs of water per mmscf of CO_2 (265 ppmwt). Dehydration with tri-ethylene glycol (TEG) typically produces a CO_2 stream with a water content of less than 7 lbs per mmscf of CO_2 (60 ppmwt). Based on an inlet feed gas composition of 151 lb water/mmscf, the unit's water removal capacity is 173 lb/hr yielding a final CO_2 stream with water content of 11 lbs per mmscf of CO_2 (60 ppmwt).

The four streams are combined and the CO_2 stream enters the bottom of the TEG contactor (VS-751) where it is contacted with lean (water-free) glycol introduced at the top of the absorber. The glycol removes water from the CO_2 by physical absorption and the rich glycol (water saturated) exits the bottom of the column. The dry CO_2 stream leaves the top of the absorption column and passes through the contactor outlet cooler (HE-751) cooling the gas to 95°F before returning to the compression section.

Regarding the rich glycol stream, after leaving the absorber it is cross exchanged with the regenerator O/H vapor stream in the reflux condenser (HE-754). Next this stream is further heated by cross exchange with the regenerator bottoms (lean glycol) stream in the cold glycol exchanger (HE-752). Next the stream enters the glycol flash tank (TK-752) where any non condensable vapors are removed.

After leaving the flash vessel, additional heating of the rich glycol occurs by cross-exchange with the regenerator bottoms (lean glycol) in the hot glycol exchanger (HE-753) before entering the regenerator column (VS-752). The glycol regenerator consists of a column, an overhead condenser (HE-754), and a reboiler (HE-755). In this column, the glycol is thermally regenerated by hot vapor stripping the water from the liquid phase.
The hot lean glycol exits the bottom of the tower and enters the reboiler where it is heated and any remaining water is flashed into vapor (steam). The steam returns to the bottom of the tower where it acts as the stripping agent, removing water from the rich glycol. Excess lean glycol in the reboiler flows over a level weir and enters a glycol surge tank. Next the hot lean glycol gravity flows through the previously described cross exchangers (HE-752/753) where it is cooled by the rich glycol. Finally a glycol pump (PU-752) pressurizes the lean glycol allowing it to return to the contactor tower (VS-751).

After the dehydrated CO_2 gas leaves the dehydration section it is split into four streams and returned for additional compression shown in Figures 4-3 through 4-6.

In the 4th stage of compression (K-604/704/804/904) the CO_2 is compressed to 1425 psia and 272°F. After this stage the streams are cooled in the compression outlet cooler (HE-704A/704B/904A/904B) to 95°F. Next, the four CO_2 streams are combined and sent to a booster pump (PU-754), which is shown in the lower half of Figure 4-2. In this pump, the stream is compressed to 2515 psia. Finally, the compressed CO_2 flows through a transmission pipeline to the injection well and subsequently into the Mt. Simon Sandstone.

For all cooling requirements, cooling tower water was supplied at 85°F and returned at 110°F. For the fired boiler, natural gas was used as the fuel supply.

4.2.4 Filter(s)

Other than the filters on the glycol circulation system, no filters are necessary due to the lack of any significant particulate matter in the CO_2 stream.

4.2.5 Injection Pump(s)

One or more injection pumps are going to be used after main compression to increase the CO_2 stream pressure to the level needed for injection into the Mt. Simon Sandstone. The final process conditions will be supplied in the completion report after the geologic information is acquired from drilling and testing of the well.

<u>Location</u>
The injection pumps will be located in the CO_2 compression building.

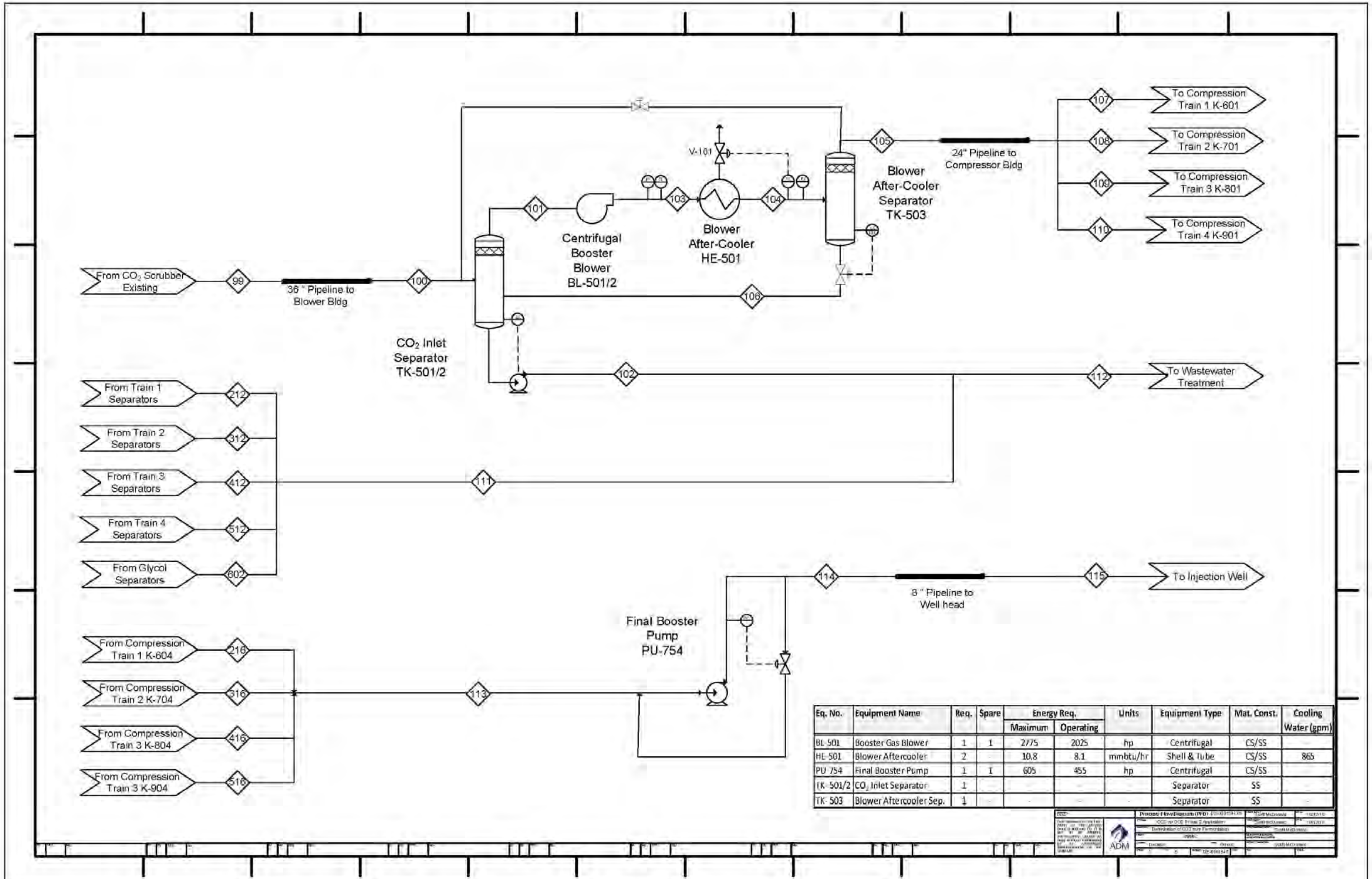
<u>Type</u>
A multistage centrifugal pump(s) will be used and the final type will be determined during the detailed design stage of the project.

Name and Model Number

The name or manufacturer of the pump(s) and model number of the pump(s) will be determined during the detailed design stage of the project.

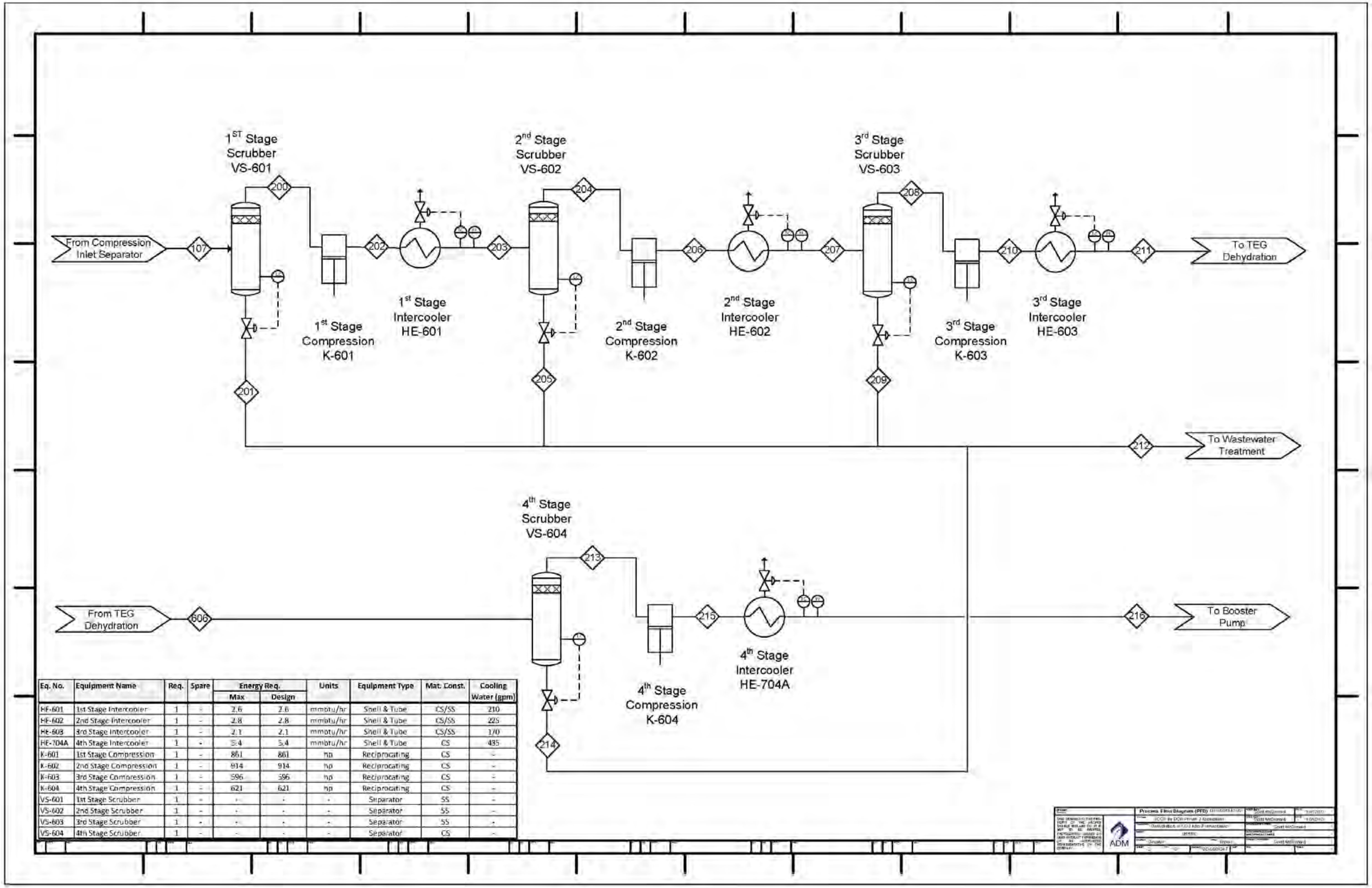
Capacity, Gallons Per Minute

The capacity of the pump(s) will be determined during the detailed design stage of the project, but the design basis is to deliver up to 3,300 MT per day of CO_2 to the wellhead.



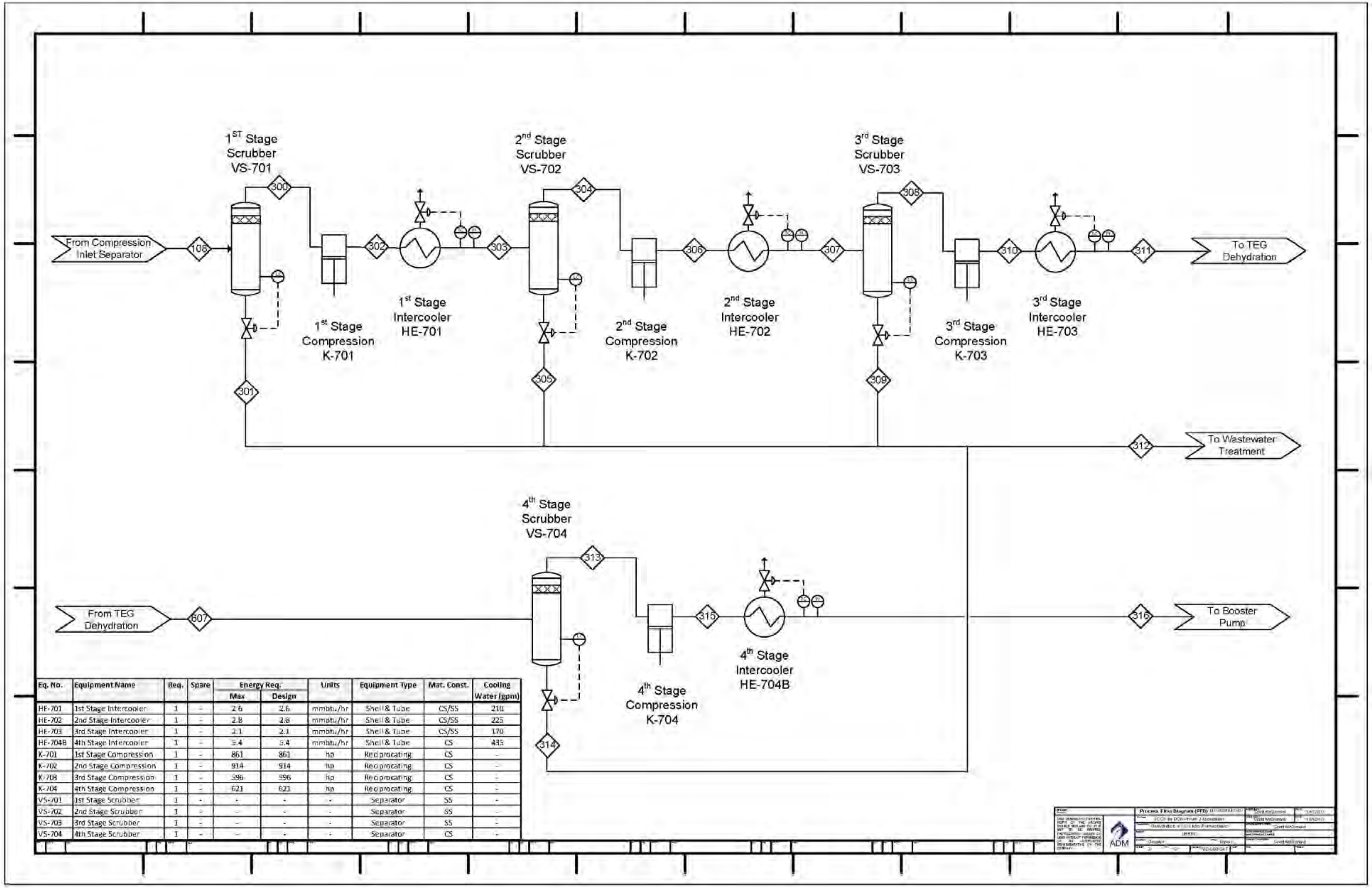
Eq. No.	Equipment Name	Req.	Spare	Energy Req.		Units	Equipment Type	Mat. Const.	Cooling Water (gpm)
				Maximum	Operating				
BL-501	Booster Gas Blower	1	1	2775	2025	hp	Centrifugal	CS/SS	-
HE-501	Blower Aftercooler	2	-	10.8	8.1	mmbtu/hr	Shell & Tube	CS/SS	865
PU-754	Final Booster Pump	1	1	605	455	hp	Centrifugal	CS/SS	-
TK-501/2	CO_2 Inlet Separator	1	-	-	-	-	Separator	SS	-
TK-503	Blower Aftercooler Sep.	1	-	-	-	-	Separator	SS	-

Figure 4-2: Booster Blower Prior to Compression and Final Pump to Well



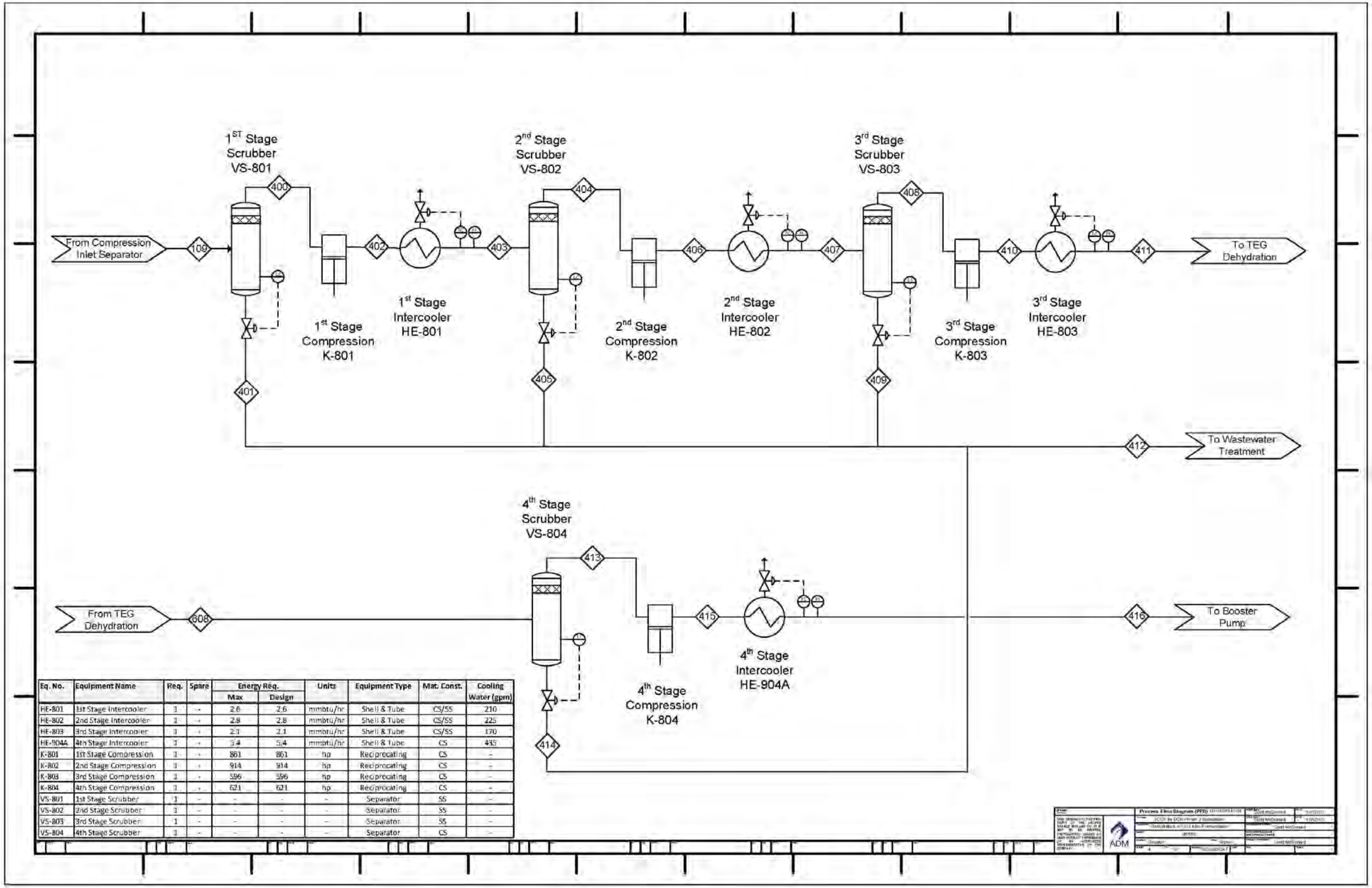
Eq. No.	Equipment Name	Req.	Spare	Energy Req.		Units	Equipment Type	Mat. Const.	Cooling Water (gpm)
				Max	Design				
HE-601	1st Stage Intercooler	1	-	2.6	2.6	mmbtu/hr	Shell & Tube	CS/SS	210
HE-602	2nd Stage Intercooler	1	-	2.8	2.8	mmbtu/hr	Shell & Tube	CS/SS	225
HE-603	3rd Stage Intercooler	1	-	2.1	2.1	mmbtu/hr	Shell & Tube	CS/SS	170
HE-704A	4th Stage Intercooler	1	-	5.4	5.4	mmbtu/hr	Shell & Tube	CS	435
K-601	1st Stage Compression	1	-	861	861	hp	Reciprocating	CS	-
K-602	2nd Stage Compression	1	-	914	914	hp	Reciprocating	CS	-
K-603	3rd Stage Compression	1	-	596	596	hp	Reciprocating	CS	-
K-604	4th Stage Compression	1	-	621	621	hp	Reciprocating	CS	-
VS-601	1st Stage Scrubber	1	-	-	-	-	Separator	SS	-
VS-602	2nd Stage Scrubber	1	-	-	-	-	Separator	SS	-
VS-603	3rd Stage Scrubber	1	-	-	-	-	Separator	SS	-
VS-604	4th Stage Scrubber	1	-	-	-	-	Separator	CS	-

Figure 4-3: Train 1 of CO_2 Compression, Stages 1-4



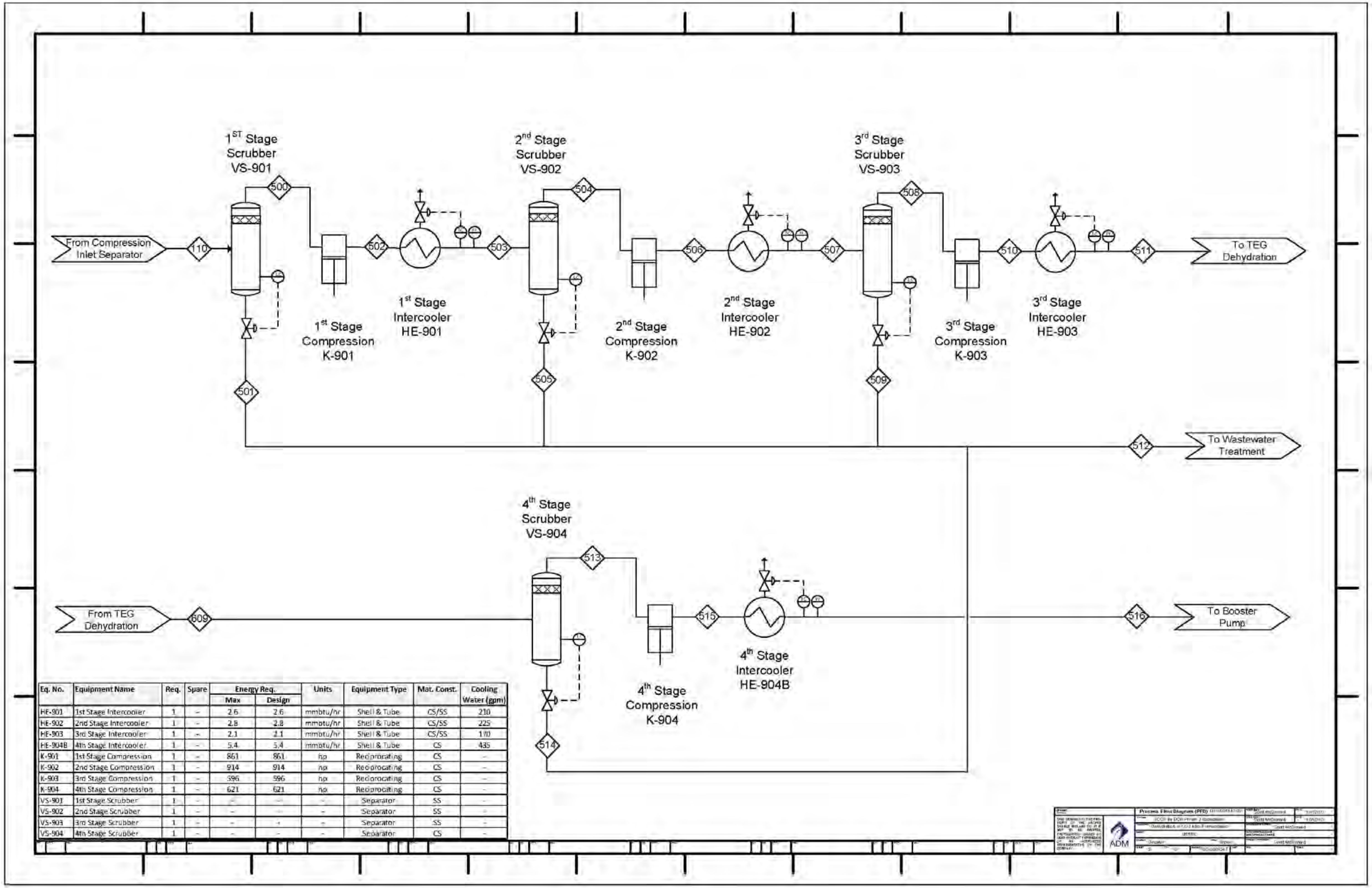
Eq. No.	Equipment Name	Req.	Spare	Energy Req.		Units	Equipment Type	Mat. Const.	Cooling Water (gpm)
				Max	Design				
HE-701	1st Stage Intercooler	1	-	2.6	2.6	mmbtu/hr	Shell & Tube	CS/SS	210
HE-702	2nd Stage Intercooler	1	-	2.8	2.8	mmbtu/hr	Shell & Tube	CS/SS	225
HE-703	3rd Stage Intercooler	1	-	2.1	2.1	mmbtu/hr	Shell & Tube	CS/SS	170
HE-704B	4th Stage Intercooler	1	-	5.4	5.4	mmbtu/hr	Shell & Tube	CS	435
K-701	1st Stage Compression	1	-	861	861	hp	Reciprocating	CS	-
K-702	2nd Stage Compression	1	-	914	914	hp	Reciprocating	CS	-
K-703	3rd Stage Compression	1	-	596	596	hp	Reciprocating	CS	-
K-704	4th Stage Compression	1	-	621	621	hp	Reciprocating	CS	-
VS-701	1st Stage Scrubber	1	-	-	-	-	Separator	SS	-
VS-702	2nd Stage Scrubber	1	-	-	-	-	Separator	SS	-
VS-703	3rd Stage Scrubber	1	-	-	-	-	Separator	SS	-
VS-704	4th Stage Scrubber	1	-	-	-	-	Separator	CS	-

Figure 4-4: Train 2 of CO_2 Compression, Stages 1-4



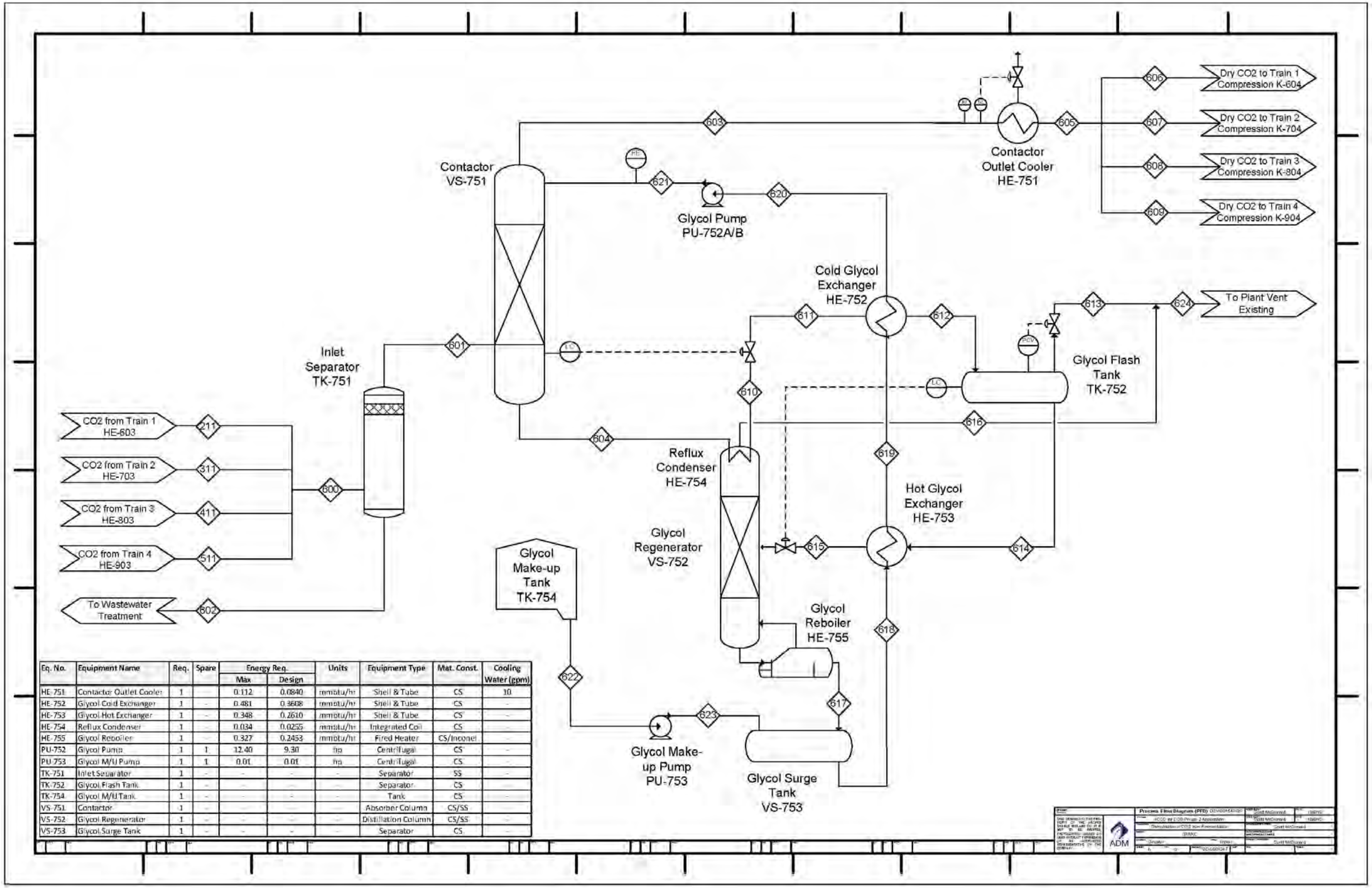
Eq. No.	Equipment Name	Req.	Spare	Energy Req.		Units	Equipment Type	Mat. Const.	Cooling Water (gpm)
				Max	Design				
HE-801	1st Stage Intercooler	1	-	2.6	2.6	mmbtu/hr	Shell & Tube	CS/SS	210
HE-802	2nd Stage Intercooler	1	-	2.8	2.8	mmbtu/hr	Shell & Tube	CS/SS	225
HE-803	3rd Stage Intercooler	1	-	2.1	2.1	mmbtu/hr	Shell & Tube	CS/SS	170
HE-904A	4th Stage Intercooler	1	-	3.4	5.4	mmbtu/hr	Shell & Tube	CS	435
K-801	1st Stage Compression	1	-	861	861	hp	Reciprocating	CS	-
K-802	2nd Stage Compression	1	-	914	914	hp	Reciprocating	CS	-
K-803	3rd Stage Compression	1	-	596	596	hp	Reciprocating	CS	-
K-804	4th Stage Compression	1	-	621	621	hp	Reciprocating	CS	-
VS-801	1st Stage Scrubber	1	-	-	-	-	Separator	SS	-
VS-802	2nd Stage Scrubber	1	-	-	-	-	Separator	SS	-
VS-803	3rd Stage Scrubber	1	-	-	-	-	Separator	SS	-
VS-804	4th Stage Scrubber	1	-	-	-	-	Separator	CS	-

Figure 4-5: Train 3 of CO_2 Compression, Stages 1-4



Eq. No.	Equipment Name	Req.	Spare	Energy Req.		Units	Equipment Type	Mat. Const.	Cooling Water (gpm)
				Max	Design				
HE-901	1st Stage Intercooler	1	–	2.6	2.6	mmbtu/hr	Shell & Tube	CS/SS	210
HE-902	2nd Stage Intercooler	1	–	2.8	2.8	mmbtu/hr	Shell & Tube	CS/SS	225
HE-903	3rd Stage Intercooler	1	–	2.1	2.1	mmbtu/hr	Shell & Tube	CS/SS	170
HE-904B	4th Stage Intercooler	1	–	5.4	5.4	mmbtu/hr	Shell & Tube	CS	435
K-901	1st Stage Compression	1	–	861	861	hp	Reciprocating	CS	–
K-902	2nd Stage Compression	1	–	914	914	hp	Reciprocating	CS	–
K-903	3rd Stage Compression	1	–	596	596	hp	Reciprocating	CS	–
K-904	4th Stage Compression	1	–	621	621	hp	Reciprocating	CS	–
VS-901	1st Stage Scrubber	1	–	–	–	–	Separator	SS	–
VS-902	2nd Stage Scrubber	1	–	–	–	–	Separator	SS	–
VS-903	3rd Stage Scrubber	1	–	–	–	–	Separator	SS	–
VS-904	4th Stage Scrubber	1	–	–	–	–	Separator	CS	–

Figure 4-6: Train 4 of CO_2 Compression, Stages 1-4



Eq. No.	Equipment Name	Req.	Spare	Energy Req.		Units	Equipment Type	Mat. Const.	Cooling Water (gpm)
				Max	Design				
HE-751	Contactor Outlet Cooler	1	-	0.112	0.0840	mmbtu/hr	Shell & Tube	CS	10
HE-752	Glycol Cold Exchanger	1	-	0.481	0.3608	mmbtu/hr	Shell & Tube	CS	-
HE-753	Glycol Hot Exchanger	1	-	0.348	0.2610	mmbtu/hr	Shell & Tube	CS	-
HE-754	Reflux Condenser	1	-	0.034	0.0255	mmbtu/hr	Integrated Coil	CS	-
HE-755	Glycol Reboiler	1	-	0.327	0.2453	mmbtu/hr	Fired Heater	CS/Inconel	-
PU-752	Glycol Pump	1	1	12.40	9.30	hp	Centrifugal	CS	-
PU-753	Glycol M/U Pump	1	1	0.01	0.01	hp	Centrifugal	CS	-
TK-751	Inlet Separator	1	-	-	-	-	Separator	SS	-
TK-752	Glycol Flash Tank	1	-	-	-	-	Separator	CS	-
TK-754	Glycol M/U Tank	1	-	-	-	-	Tank	CS	-
VS-751	Contactor	1	-	-	-	-	Absorber Column	CS/SS	-
VS-752	Glycol Regenerator	1	-	-	-	-	Distillation Column	CS/SS	-
VS-753	Glycol Surge Tank	1	-	-	-	-	Separator	CS	-

Figure 4-7: Tri-Ethylene Glycol Dehydration Process

SECTION 6A – INJECTION WELL MONITORING, INTEGRITY TESTING, AND CONTINGENCY PLAN

This section is intended to satisfy the requirements of 40 CFR 146.90.

6A.1 Fluid Sampling and Analysis of the CO_2 Injectate

6A.1.1 Sampling Frequency

As detailed in Section 7 of this application, the injection stream (injectate) is high purity CO_2 with trace levels of other constituents. The CO_2 vent stream from biofuel fermentation is relatively consistent with respect to composition and mass due to the nature of the process and also a result of the operation of the vent scrubber system to remove volatile organic compounds. The scrubber system operates within established parameters in accordance with air permitting requirements. Based on these stream characteristics, quarterly sampling of the CO_2 is proposed.

6A.1.2 Analysis Parameters

Each sample will be analyzed for the parameters listed in Appendix E – Material Analysis Plan.

Unlike captured CO_2 from the combustion of fossil fuels, the ADM CO_2 stream produced from the ethanol plant is very pure. The parameters were selected based on the typical impurity profile for CO_2 produced during the anaerobic fermentation of sugars to ethanol. These parameters and the monitoring process are intended to ensure that the CO_2 stream does qualify as hazardous waste or pose a corrosion risk to the facility's materials of construction. Methods to measure the composition of the CO_2 stream will conform to applicable chemical analytical standards like ASTM standard E1747-95 (Reapproved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications.

6A.1.2.1 CO_2 Corrosivity

A water saturated CO_2 stream can be corrosive to carbon steel as reported by Dugstad, Lunde, and Nesic (1994). Therefore the metallurgy used prior to the gas dehydration unit is 316SS which is resistant to CO_2 corrosion as reported by Bruce D. Craig and Liane Smith (2011).

The gas dehydration unit will reduce the water content of the CO_2 to a range of 7 to 30 lb of H_2O/MMSCF (150 to 630 ppmv H2O). This water content range is consistent with typical U.S. CO_2 transmission pipeline water content specifications for carbon steel pipe, therefore, no corrosive reactions are anticipated. An online water analyzer using tunable diode laser absorption spectroscopy will be employed downstream of the dehydration unit to monitor the water content of the injectate.

Additionally the project will employ a corrosion monitoring plan in order to monitor the corrosion potential of materials that will come in contact with the carbon dioxide stream. This plan is detailed in section 6A.3.5 of the application.

6A.1.2.2 CO_2 Toxicity

Carbon dioxide gas is an asphyxiant with effects due to lack of oxygen. It is also physiologically active, affecting circulation and breathing. CO_2 has the following exposure limits:

OSHA PEL = 5,000 ppm
ACGIH TLV-TWA (2007) = 30,000 ppm 15 min STEL
IDLH = 40,000 ppm
LC_{Lo} = 90,000 ppm, 5 min., human

Installation of CO_2 atmospheric monitors will be employed within the compression facility and the storage site to alert operations personnel about elevated levels of CO_2 in excess of OSHA personnel exposure limits.

A material safety data sheet for CO_2 is presented in Appendix E.

6A.1.3 Sampling Location

Sampling will be conducted downstream of the vent scrubber. The locations and details of the sample points are undetermined. The finalized sample point design and locations will be included in the well completion report.

6A.1.4 Detailed Injectate Fluid Analysis Plan

A detailed injectate material analysis plan is included as Appendix E.

Methods to measure the composition of the CO2 stream will conform to applicable chemical analytical standards and may include ASTM standard E1747-95 (Reapproved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications.

6A.2 Monitoring Program

The permit holder will use the site infrastructure employing methods to achieve the UIC Class VI program's objectives and requirements in the following categories:

- Mechanical Integrity Tests
- Operational Testing and Monitoring
- Plume and Pressure-Front Tracking
- Ground Water Quality and Geochemistry Monitoring
- Soil Gas and Surface Air Monitoring

The comprehensive program focuses on ensuring that the subsurface zones above the confining zone are not compromised by the injection and storage of CO_2 within the Mt. Simon Sandstone. To meet the goals of the program, the subsurface monitoring program focuses on four zones:

1. Pleistocene and Pennsylvanian sands – the source of local drinking water.
2. The St. Peter Sandstone – the lowermost underground source of drinking water.
3. The Ironton-Galesville Sandstone – the zone above the confining Eau Claire cap rock.
4. The Mt. Simon Sandstone – the injection and storage zone.

Appendix F details the monitoring program developed for each of these zones.

The monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone.

In addition to monitoring at the injection well (CCS#2), the operator will drill and complete one observation well (Verification Well #2) that penetrates the Mt. Simon Sandstone in order to provide another injection zone monitoring point. Other site monitoring includes the use of a shallower observation well to be named Geophysical Monitor #2 (GM#2). Details on the monitoring techniques used in these observation wells are described in Sections 6B and 3C, respectively. A summary of the sites various wells and their capabilities is shown in Table 6A-1. This summary includes the wells already employed by the Illinois Basin Decatur Project (IBDP). The infrastructure and data from both projects will be integrated to provide a comprehensive site monitoring program.

Table 6A-1: ADM Decatur Site Monitoring Infrastructure

	IL ICCS Wells			IBDP Wells		
	CCS #2	VW #2	GM #2	CCS#1	VW #1	GM #1
Approx. Depth (ft)	7200	7200	3500	7200	7200	3500
Approx. Distance from CCS#2 (ft)	0	2600	100	3700	2800	3800
Capable of obtaining:						
Mt. Simon pressure(s)/temperature(s)	yes	yes	no	yes	yes	no
Mt. Simon fluid sampling	no	yes	no	no	yes	no
Ironton Galesville pressure/temperature	no	no	no	no	yes	no
Ironton Galesville sampling	no	no	no	no	yes	no
St. Peter pressure/temperature	no	no	yes	no	no	no
St. Peter fluid sampling	no	no	yes	no	no	no
RST Logging (near wellbore CO_2 detection)	yes	yes	yes	yes	yes	yes
Seismic Imaging of CO_2 plume	no	no	yes	no	no	yes
Annulus Pressure at surface	yes	yes	yes	yes	yes	yes
Injection Pressure at surface	yes	no	no	yes	no	no

* Deeper formations only. Shallow USDW monitoring not included in this table

Monitoring at the injection well will include annual surveys which are described in Section 6A.3.2. Details about the continuous operational monitoring are described below.

6A.2.1 Recording Devices

All essential monitoring, recording, and control devices will be functional prior to injection operations. Essential operational monitoring will be continuous and includes: injection flow rate and volume, well head injection pressure, well head injection temperature, and well head casing annulus pressure. A description of the surface facility equipment and control system is presented in section 6A.2.2.3 of this application. Regarding the annular pressure, monitoring this parameter will provide the information necessary to determine whether there is a failure of the casing-cement bond, injection tubing, and/or down hole isolation devices - packers. A description of the continuous annular pressure monitoring system is presented in section 6A.3.1 of this application. Regarding the injectate, the CO_2 is a dry supercritical fluid, therefore no pH recording devices are warranted; however an online water analyzer using tunable diode laser absorption spectroscopy will be employed downstream of the dehydration unit to monitor the water content of the injectate. Additionally, corrosion coupons will be installed to indirectly monitor corrosion on the process piping and equipment. This plan is fully described in Section 6A.3.5 - Corrosion Monitoring Plan.

6A.2.2 Control and Alarm System for the Well Monitoring and Maintenance

Alarms and shutdown systems will be installed and functional prior to injection operations. In order to meet the permit requirements, alarm and shutdowns systems will be initiated for deviations on essential operating parameters. These parameters include injection flow rate and volume, well head injection pressure, and well head casing annulus pressure. During shutdown events, the master control and monitoring system will be programmed to take the appropriate action for each specific event in order to safeguard the facility. Actions may include but are not limited to wellhead isolation, pipeline isolation, system venting (de-pressuring), and process equipment shutdown. Table 6A-2 lists the essential surface injection operating parameters. A description of the surface facility equipment and control system is presented in section 6A.2.2.3 of this application. A description of the continuous annular pressure monitoring system is presented in section 6A.3.1 of this application.

Table 6A-2: Surface injection operating parameters.

Surface Injection Parameter	**Operating Range**
CO_2 Injection Flow Rate	Up to 3,300 metric tons/day
Flow Rate Variation	+/- 10% of flow rate set point
Wellhead Inlet Pressure	< 2,380 psig
Annulus pressure at surface	> 500 psig

6A.2.2.1 Control System Overview

The surface facility's process flow diagrams (PFDs), which include the compression, dehydration, and transmission equipment, are provided in Section 4 – Injection Well Operation, while the piping & instrument diagrams (P&IDs) for these facilities can be found in Appendix C. These diagrams detail the facility's equipment, configuration, instrumentation, surveillance, and control systems. A process narrative describing the facility's equipment and control equipment is presented in Section 6A.2.2.3 – Surface Facility Equipment & Control System Description.

6A.2.2.2 Wellbore and Wellhead Design

The design of the injection well includes but is not limited to the following:

1. A dual master and single wing Xmas tree assembly with a swab valve above flow tee. Upper master will have an automatic shutoff capability. Wing valve will have an automatic valve (current design calls for a check valve) installed directly upstream of the wing valve to prevent backflow into the pipeline.

2. All annuli will have pressure gauges and sensors to detect any abnormal pressure spikes.

3. Injection pressures will be monitored and recorded at the compressor discharge and at the wellhead. Additionally, the pressure of the wellhead casing annulus will be monitored and recorded.

4. Along with continuous, real time recording and automatic shut-down systems, field operations personnel will perform daily rounds and routine inspections of the compression, dehydration, and transmission facilities as well as the well sites to ensure the integrity of the surface systems and apparent functionality of mechanical equipment.

5. All Xmas tree equipment is rated to at least 3,000 psig working pressure, plus the Xmas tree assembly (upper valve assembly) is constructed of stainless steel and/or chrome. Based on expected bottomhole pressures and other well controls and limitations, we will not exceed the working pressure of the 3,000 psi well head in any application or under any operating conditions. The maximum calculated injection pressure is 2,380 psig.

6. Normal operating pressure at the wellhead will be 2,380 psig or less. Alarms will be set at 2,350 psig and automatic shutdown will occur at 2,380 psig. Maximum surface injection pressure at the wellhead will be 2,380 psig.

The operating range of surface facilities instruments will address the minimum and maximum expected operating conditions for each instrument (surface pressure gauges, temperature gauge, annulus pressure gauges, etc.). The instruments will include an operating range that is at least 20% outside the expected maximum and (if required) minimum operating range.

If communication (and subsequent data archiving) is lost for any reason with any portion of the monitoring system, an investigation will immediately be conducted to determine the cause, and actions taken to restore communications. Injection will be shut down only under certain circumstances (reference the contingency plan in Section 6A.4). In the special case of wellhead surface pressure and annulus pressure, if communication is lost for greater than 30 minutes, project personnel will perform field monitoring of manual gauges every four hours for both parameters and record the data until communication is restored. An example of a form for maintaining the record is included in Figure 6A-1.

Figure 6A-1: Example Field Log Form for Manual Injection Well Gauge Readings

FIELD LOG – INJECTION / VERIFICATION WELLS
(For back up field data collection in the event of power outage or other data transmission loss from automated gauges – see "*Instructions*")

Illinois EPA Site #1150155136 – Macon County Archer Daniels Midland – Corn Processing Carbon Sequestration Injection and Verification Wells	Permit No. Well No. UIC Log #

ADM Supervisor: ______________________________

Readings Taken by: Name:______________________________

Phone:______________________________

Check Box(es) Above Failed Instrument(s) ➔						
DATE	**TIME**	**Injection Wellhead Pressure** PIT-009 (psig)	**Injection Annulus Pressure** PIT-014 (psig)	**Verification Tubing Pressure** Westbay (psig)	**Verification Annulus Pressure** Westbay (psig)	**INITIALS**

***INSTRUCTIONS –** Within 30 minutes of a communication loss, manual readings of the pressure in the tubing and annulus of both wells will be taken and recorded, and continued every 4 hours thereafter until communication is restored.*

6A.2.2.3 Surface Facility Equipment & Control System Description

The description of the equipment and operating controls for the Surface Facilities is as follows (reference Piping & Instrument Diagrams (P&IDs) in Appendix C):

Collection and Blower Area

The P&IDs detail the surface facility's equipment, configuration, instrumentation, surveillance, and control systems. The compression train receives the low pressure (~0.5 psig) CO_2 from the primary CO_2 scrubber's overhead, gas outlet, line. From the scrubber, the CO_2 gas stream is sent to the blower inlet separators, TK-501/2, where condensed liquid, mainly free water carried over from the scrubber, is removed. The water level in the separators is controlled via start/stop of the inlet separators water pumps through level transmitters/controller LT-501/2. The pressure (PTX-501A/2A) and temperature (TIT-501A/2A) of the separators overhead CO_2 gas stream are measured before the stream enters the blowers, BL-501/2, where the CO_2 pressure is increased by approximately 16 psi. The blower outlet temperature and pressure are monitored and alarmed by TIT-501B/2B and PTX-501B/2B. At this point, the CO_2 stream is monitored for oxygen by an online gas analyzer ARX- 001. A high oxygen reading may indicate an air leak or instrument failure that would allow air into the system through a flange leak or through the CO_2 scrubber's vent stack. In the event of high oxygen alarm, the operational staff would initiate steps to determine the source of the alarm condition and to take corrective action. After compression, the gas stream is cooled by the blower aftercooler exchanger, HE-501. The cooler outlet gas temperature is measured by TIT-503A and controlled at a set point (95°F) via TCV-503A; located on the exchanger's cooling water return line. The exchanger's cooling water inlet and outlet conditions are indicated by TI-502/3 and PI-503.

Next, the CO_2 stream enters the blower after cooler separator, TK-503, where any condensed liquid is removed. The water inventory in TK-503 is controlled by level controller LIC-502 via control valve LCV-502. The blower's discharge stream pressure is controlled by PTX-502B via variable frequency drive, VFD-502, controlling the blower motor, BLM-503. This control system is not shown on the enclosed PIDs but will be detailed on the finalized construction PIDs and included with the well completion report. Additional high pressure control is provided by PIC-502 located on TK-503's overhead gas outlet line which safely vents the CO_2 to atmosphere via control valve PCV-502. After cooling and water removal, the CO_2 stream is transported to the main compression building through 1,500 feet of 24" line. At the compression building, the CO_2 stream is split and enters the suction of four reciprocating compressors, K-600/700/800/900. Each compressor operates in parallel and is a six throw (cylinder) machine with 4-stages of compression.

Main Compression Area – Stages 1-3

During CO_2 compression, each stage follows a sequence of free liquid removal, pulsation dampening, compression, pulsation dampening, and cooling before moving to the next compression stage. The following paragraph provides a process narrative for K-600. The other compressors will have identical equipment and control elements.

In the 1st stage of compression, the CO_2 stream enters the 1st stage scrubber, SR-601, where any free liquid is removed. The scrubber level is controlled by LIC-601 via control valve LCV-601. The compressor's feed stream conditions (suction side) are indicated and alarmed by TIT-601A and PTX-601A. After liquid knock out, the CO_2 stream passes through the 1^{st} stage suction (pulsation) bottle, K-601A, before being compressed in cylinders #1 and #3. In this stage, the gas is compressed to 75 psia, after which it passes through the 1^{st} stage discharge (pulsation) bottle, K-601B. High compressor discharge temperature is monitored and alarmed by TIT-601B/C. Pressure safety valves, PSV-601C/D, provide over pressure protection on the compressor discharge. Next, the gas is cooled to 95°F by the 1^{st} stage intercooler, HE-601, before moving to the 2^{nd} stage of compression.

In the 2^{nd} stage, the CO_2 stream passes through the 2^{nd} stage scrubber, SR-602, where any free liquid is removed. The scrubber level is controlled by LIC-602 via control valve LCV-602. The 2^{nd} stage suction conditions are indicated and alarmed by TIT-602A and PTX-602A. After liquid knock out, the CO_2 stream passes through the 2^{nd} stage suction bottle, K-602A, before compression to 249 psia in cylinders #2 and #4. The compressor discharge temperature is monitored and alarmed by TIT-602B/C. Pressure safety valves, PSV-601A/B, provide over pressure protection on the compressor discharge. Next the compressed CO_2 stream passes through the 2^{nd} stage discharge bottle, K-602B, and is cooled to 95°F in the 2^{nd} stage intercooler, HE-602, before moving to the 3^{rd} compression stage.

In the 3^{rd} compression stage, the CO_2 stream enters the 3^{rd} stage suction scrubber, SR-603, where free liquid is removed. The scrubber level is controlled by LIC-603 via control valve LCV-603. The 3^{rd} stage suction conditions are monitored and alarmed by TIT-603A and PTX-603A. After liquid removal, the CO_2 stream passes through the 3^{rd} stage suction bottle, K-603A, followed by compression to 598 psia in cylinder #6, before traveling through the 3^{rd} stage discharge bottle, K-603B. The compressor discharge temperature is monitored and alarmed by TIT-603B/C. Pressure safety valves, PSV-603A/B, provide over pressure protection on the compressor discharge. Next, the gas is cooled to 95°F by the 3^{rd} stage intercooler, HE-603, before further processing.

Dehydration Area
At this point in the process, 95% of the water entering with the CO_2 stream has been removed through compression and cooling. After the third stage of compression, the CO_2 stream contains approximately 1300 ppmwt H_2O. Because this exceeds the recommended water content for subsurface injection, the four streams are combined to be sent to the glycol dehydration skid, shown in PD-09/10.

The design basis for the dehydration unit is to remove enough water from the CO_2 stream to insure the exiting stream contains no more than 30 lbs of H_2O per mmscf of CO_2, approximately 265 ppmwt H_2O. Dehydration with tri-ethylene glycol (TEG) typically produces a CO_2 stream with a water content of less than 7 lbs per mmscf of CO_2 (60 ppmwt H_2O). Based on an inlet feed gas composition of 151 lbs H_2O/mmscf, the unit's water removal capacity is 173 lbs/hr yielding a final CO_2 stream with water content of 11 lbs H_2O per mmscf CO_2 (60 ppmwt H_2O).

After the 3^{rd} compression stage, the four streams are combined and enter the dehydration inlet separator, TK-751, where any free liquid is removed. After liquid removal, the gas stream enters the bottom of the TEG glycol contactor, VS-751, where it is contacted with lean (water-free) glycol introduced at the top of the contactor. The glycol removes water from the CO_2 by physical absorption and the rich glycol (water saturated) exits the bottom of the column. The dry CO_2 stream leaves the top of the contactor and passes through the glycol heat exchanger, HE-

751, where the gas is cooled to 95°F, via cross exchange with lean glycol, before returning to the compression section.

Regarding the rich glycol stream, after leaving the contactor it is cross exchanged with the regenerator O/H vapor stream in the reflux condenser coil in the top of the glycol still, VS-752. Next this stream is further heated by cross exchange with the regenerator bottoms (lean glycol) stream in the cold glycol exchanger, HE-752. Next the stream enters the glycol flash tank, TK-752, where any non-condensable vapors are removed by venting through PCV-751.

After leaving the flash vessel, the glycol is filtered and polished by FR-754A/B, glycol solids filter, and FR-755A/B, rich glycol carbon filter. Next, additional heating of the rich glycol occurs by cross-exchange with the regenerator bottoms (lean glycol) in the hot glycol exchanger, HE-753, before entering the glycol still column, VS-752. The glycol regeneration equipment consists of a column, an overhead condenser coil, and a reboiler, HE-755. In the still column, the glycol is thermally regenerated via hot vapor stripping the water from the liquid phase.

The hot lean glycol exits the bottom of the tower and enters the reboiler where it is heated and any remaining water is flashed into vapor (steam). The steam returns to the bottom of the tower where it acts as the striping agent removing water from the rich glycol descending the still. Excess lean glycol in the reboiler flows over a level weir and enters a glycol surge tank. Next the hot lean glycol gravity flows through the previously described cross exchangers (HE-752/753) where it is cooled by the rich glycol. Finally the glycol pumps, PU-752A/B pressurizes the lean glycol, after which it is cooled through cross exchange with dry CO_2 in HE-751, and returns to the top of the glycol contactor, VS-751, starting another process cycle.

After dehydration the CO_2 stream is monitored and alarmed for water content by gas analyzer ARX-006 (see PD-21), after which the stream is split and returned to the four compressors 4th stage.

Main Compression Area – Stage 4 and Booster Pumps

As with the previous compression stages, the CO_2 stream enters the 4th stage suction scrubber, SR-604, where any free liquid is removed. The scrubber level is controlled by LIC-604 via control valve LCV-604. The compressor's feed stream conditions (suction side) are indicated and alarmed by TIT-604A and PTX-604A. After liquid knock out, the CO_2 stream passes through the 4th stage suction (pulsation) bottle, K-604A, before being compressed in cylinder #5. In this stage, the gas is compressed to 1425 psia, after which it passes through the 4th stage discharge (pulsation) bottle, K-601B. High compressor discharge temperature is monitored and alarmed by TIT-601B/C. Next, the gas is cooled to 95°F by the 4th stage aftercooler, HE-704A/B, before further compression. The compressor's discharge pressure control is accomplished by PIC-604C via PCV-604C, which recycles gas to the 1st stage scrubber, SR-601. Additional high pressure control is provided by pressure relief valve PSV-604A/B, which safely vents the stream to atmosphere.

After cooling, the CO_2 streams are combined and sent to the CO_2 multistage centrifugal pumps, PU-754A/B/C. Here the CO_2 stream is in a dense phase and is compressed to 2,565 psia and transported to the injection well by 5,000 feet of 8" pipeline. Flow to the wellhead is monitored by flow indicating transmitter FIT-006 and is controlled by flow controller FC-006 by changing the set point on the pump's variable frequency drive, VFD-754A/B/C. Additionally a pressure indicating transmitter, PIT-007 will provide a high pressure protection by allowing the pressure transmitter to reset the flow. The final high pressure control is provided on the pump discharge by pressure relief valves PSV-082/083/084(A/B), which safely vent the stream to atmosphere.

Transmission Line and Injection Well
As mentioned previously, the CO_2 stream is transported to the injection well via a 5,000 foot pipeline constructed of 8" schedule 120 carbon steel. The pipeline is equipped with automated block valves NV-023, located at the compressor building (see PD-13), and MOV-023, located at the wellhead (see PD-40), as part of the control system for isolating the pipeline and injection well during a shutdown event. At the injection well site, monitoring and alarm of stream parameters is accomplished with temperature indication TIT-009 and pressure indication PIT-012.

Additional overpressure protection is provided on the pipeline by two spring-operated thermal relief valves, TRV-001 and TRV-002. The purpose of these valves is to relieve pressure resulting from the thermal expansion of the fluid if the pipeline is isolated for a shutdown event.

Master Control and Surveillance System
Regarding the UIC Class VI permit conditions, the control system will limit maximum flow to 3,300 MT/day and/or limit the well head pressure to 2,380 psig, which corresponds to the regulatory requirement to not exceed 90% of the injection zone's fracture pressure. All injection operations will be continuously monitored and controlled by the ADM operations staff using the distributive process control system. This system will continuously monitor, control, record, and will alarm and shutdown if specified control parameters exceed their normal operating range.

The CO_2 compression, transmission, and injection system has a robust control and surveillance structure programmed to identify abnormal operating conditions and/or equipment malfunctions, automatically make the appropriate process response, annunciate the condition to ADM operations personnel staff, and to shut down the process equipment under certain conditions.

More specifically, all critical system parameters, e.g., pressure, temperature, and flow rate will have continuous electronic monitoring with signals transmitted back to a master control system. A list of these instruments, with the instrument description/location, tag number, type of instrument, brand/model number, service, compatibility and operating range information, will be provided within the well completion report. The list will also indicate whether the instrument activates a shutdown of the surface equipment. Real time monitoring for water and oxygen content is also included in the plant design. The recording devices, sensors and gauges will meet or exceed the maximum operating range by 20%.

ADM supervisors and operators will have the capability to monitor the status of the entire system in two locations: the compression control room (near the main compressors), and the main Alcohol Department control room. Should one of the parameters go into an alarm status, the control system logic will automatically make the necessary changes, including shutting down the entire compression system if warranted. At the same time, audible and visual alarms will activate in both the compression control room and the main Alcohol Department control room. Alcohol Department supervision will respond to the alarms, identify the problem, and dispatch the necessary resources to address the problem.

A loss of power to the compression system will shut down surface compression and injection. Automatic shutdown valves NV-023, located at the compressor building, and MOV-023, located at the wellhead, V-347 will automatically isolate the pipeline. Additionally, check valve at the wellhead will prevent the backward flow of CO_2 from the wellhead.

A Hazard and Operability Study (HAZOP) was conducted for the design of the CO_2 compression and dehydration portions of the Surface Facilities. The process nodes evaluated during the HAZOP were blower, reciprocating compression Stages 1, 2, 3 and 4, and the dehydration unit, centrifugal pump, pipeline, and wellhead systems. Engineering and administrative controls were specified for each of the consequences identified during the HAZOP.

6A.2.3 USDW Monitoring in Area of Review

In Macon County, water wells are commonly used as a local source of drinking water. The wells are drilled into the Pleistocene and Pennsylvanian sands. Some water wells are completed in the shallow bedrock, but water quality deteriorates rapidly with depth. Available information shows that sand and gravel deposits are not uniformly distributed throughout the county (Larson et al., 2003, Figure 6A-2) and may not be found continuously beneath the IL-ICCS site. A groundwater monitoring plan has been developed for this zone and is presented in Appendix F1. Most water wells in the AoR have depths ranging from 70 to 101 feet (Figure 6A-3), which coincides with the depth of the upper Glasford Aquifer (Figure 6A-4). Because the Illinois EPA determined that the Pennsylvanian bedrock was the lowermost USDW, the initial application focused the USDW monitoring plan on this zone. However on March 21, 2012, the USEPA made the determination that the St. Peter Sandstone is the lowermost underground source of drinking water within the AoR of this permit application. Therefore, a groundwater monitoring plan has been developed for this zone and is presented in Appendix F2.

6A.2.4 Detailed Groundwater Monitoring Plan

The groundwater monitoring plan focuses on four zones:

1. Pleistocene and Pennsylvanian sands – the source of local drinking water.
2. The St. Peter Formation – the lowermost underground source of drinking water.
3. The Ironton-Galesville Sandstones– the zone above the confining Eau Claire cap rock.
4. The Mt. Simon Sandstone – the injection and storage zone.

Appendix F1 presents the groundwater monitoring program for the Pleistocene and Pennsylvanian aquifers. Because these aquifers are not the lowermost source of drinking water and because this monitoring zone has no significant chance of being compromised by the injection and migration of CO_2 as discussed in Section 6A.2.6.1, the groundwater monitoring program for this zone is deemed voluntary. All data developed by this monitoring plan will be available to the agency upon request. The groundwater monitoring plan presented in Appendix F1 is strictly informational.

Appendix F2 presents the groundwater monitoring plan for the St. Peter Sandstone, the aquifer designated the lowermost source of drinking water (USDW).

Appendix F3 presents the groundwater monitoring plan for the Ironton-Galesville, the saline aquifer directly above the primary seal formation.

Appendix F4 presents the groundwater monitoring plan for the Mt. Simon Sandstone, the injection and storage formation.

6A.2.5 Tracking Extent and Pressure of CO_2 plume

Identification of the position of the injected carbon dioxide plume and the presence or absence of elevated pressure (i.e., the pressure front) is integral to protection of USDWs for Class VI projects. Regions overlying the separate-phase (i.e., liquid, gaseous or supercritical) carbon dioxide plume and area of elevated pressure may be at enhanced risk for fluid leakage that may endanger a USDW. Monitoring the movement of the carbon dioxide and the pressure front is necessary to both identify potential risks to USDWs posed by injection activities and to verify predictions of plume movement. Monitoring results from all of these methodologies can also provide necessary data for comparison to model predictions, and inform reevaluation of the AoR. (USEPA GS_Testing and Monitoring Guidance. Jan 2012)

The proposed methods for Plume and Pressure-Front Tracking for the IL-ICCS project include direct pressure monitoring, reservoir saturation measurements (RST) using pulsed neutron cased hole logging technology, and indirect geophysical monitoring via the use of seismic surveys. The observation wells will be designed and completed to provide capabilities for geochemical monitoring, i.e. fluid sampling. Pre-injection fluid sampling to provide baseline constituent analysis will be performed in the event that the other plume and pressure front tracking measurements or methods indicate a need for subsequent sampling. All site data from the methods mentioned here will be incorporated into a comprehensive mathematical model of the site. ECLIPSE is the tool which will be used. The model will be calibrated using these datasets.

Direct pressure monitoring in the injection well (CCS#2) will be done via pressure gauge installed at surface (at the wellhead). Additionally, a downhole pressure gauge will be located at the packer. These gauges will record the inside tubing pressure and temperature. These pressure measurements will be helpful in monitoring changes in reservoir pressure during the lifetime of the project.

Other in situ pressure measurements of the injection zone will be done in Verification Well #2 (VW#2) and are described in Section 6B. These measurements are intended to show the anticipated buildup of pressure in the lower Mt. Simon injection zone while demonstrating that the upper Mt. Simon remains near the pre-injection pressure. The pressure measurements from Verification Well #1 (VW#1) and GM#2 are anticipated to show that pressure changes are not occurring in the zones above the Eau Claire confining zone.

The use of Schlumberger's Reservoir Saturation Tool (RST) to monitor the presence or absence of CO_2 in the reservoir has proven to be very successful. The upper boundary of CO_2 can be readily identified in CCS#1 and VW#1. RST will be used in the ICCS project as an integral input for plume tracking, model calibrations, and mechanical integrity verifications. The use of RST as a CO_2 monitoring tool has been described by Butsch and Malkewicz in their poster presented at the 2010 NETL Annual Conference, held in Pittsburgh, PA. 10-13 May 2010. Enhanced Oil Recovery projects have also utilized RST as a viable method for monitoring carbon dioxide floods (Al-Aryani et al, 2011).

As with the Illinois Basin – Decatur Project (IBDP), a combination of time-lapse seismic monitoring technologies will be used to image the CO_2 plume as the project progresses. The primary objective of time-lapse seismic surveys is to monitor qualitative changes in a formation that occur as a result of fluid injection or production.

Rock properties, such as the bulk modulus and density, of a formation change as CO_2 is injected into the formation. In turn, changes to the bulk modulus and density affect measureable seismic parameters like P-wave velocity (V_P) and S-wave velocity (V_S). Supercritical CO_2 is as much as 15 times more compressible than brine (White et al., 2004). Injecting supercritical CO_2 into a formation will decrease the bulk density of the formation and will result in an observable decrease in V_P as well as potentially large impedance contrasts at the injection interval (Couëslan, 2007 and Arts and Winthaegen, 2005). Active time-lapse seismic surveys aim to record these changes.

In the early stages of injection, time-lapse 3D vertical seismic profiles (VSPs) will likely be used to image the developing CO_2 plume. The 3D VSPs will be acquired in GM#2, which is immediately to the northwest of the proposed site of the new injection well (CCS#2). 3D VSPs are an attractive alternative to 3D surface seismic surveys, as they have smaller acquisition footprints that are less disruptive to the surrounding community and cost less to acquire. Time-lapse 3D VSPs have been used successfully to monitor injection and production operations in both on- and offshore environments (Wu et al., 2011 and O'Brien et al., 2004). In particular, time-lapse 3D VSPs were used as a primary monitoring technology to monitor injected CO_2 at the Monell CO_2 EOR pilot project in Wyoming (O'Brien et al., 2004).

Time-lapse 3D surface seismic surveys are now widely used to monitor oil and gas operations around the world. With respect to CO_2 storage projects, the most well-known projects are the Sleipner Project in the Norwegian North Sea and IEA GHG Weyburn-Midale Project in Saskatchewan, Canada (White et al., 2004 and Chadwick et al., 2010). Both of these projects have been injecting CO_2 for storage or EOR for over a decade and time-lapse surface seismic data has been used to image the developing CO_2 plume from an early stage.

In the case of IBDP, the 3D VSP data acquired in GM#1 images out to a radius of approximately 2500 ft at the depth of CO_2 injection into the Mt. Simon Sandstone (Figure 1). A similar imaging aperture is expected from any 3D VSPs acquired in GM#2, as this well will be drilled to a similar depth of 3500 ft and the geology is fairly flat between the two locations. Time-lapse 3D VSPs acquired in GM#2 will be able to monitor the plume related to CCS#2 within the 2,500 ft radius. The acquisition footprint of the 3D VSPs acquired in GM#2 will cover an area similar to the IBDP 3D VSP surveys; however, they will likely use a smaller source spacing based on the lessons learned from IBDP. Current plans are to use a retrievable tool to acquire the 3D VSP surveys in GM#2 rather than using a cemented permanent geophone array.

At the end of the injection period, either a series of 2D surface seismic lines or a final time-lapse 3D surface seismic survey may be utilized to image the final plume. It is expected that the monitoring, verification, and accounting (MVA) data collected over the course of injection will assist in making a final decision on the type of surface seismic survey. For instance, a final surface seismic survey may be needed if the CO_2 plume migrates beyond the imaging aperture of the 3D VSP data.

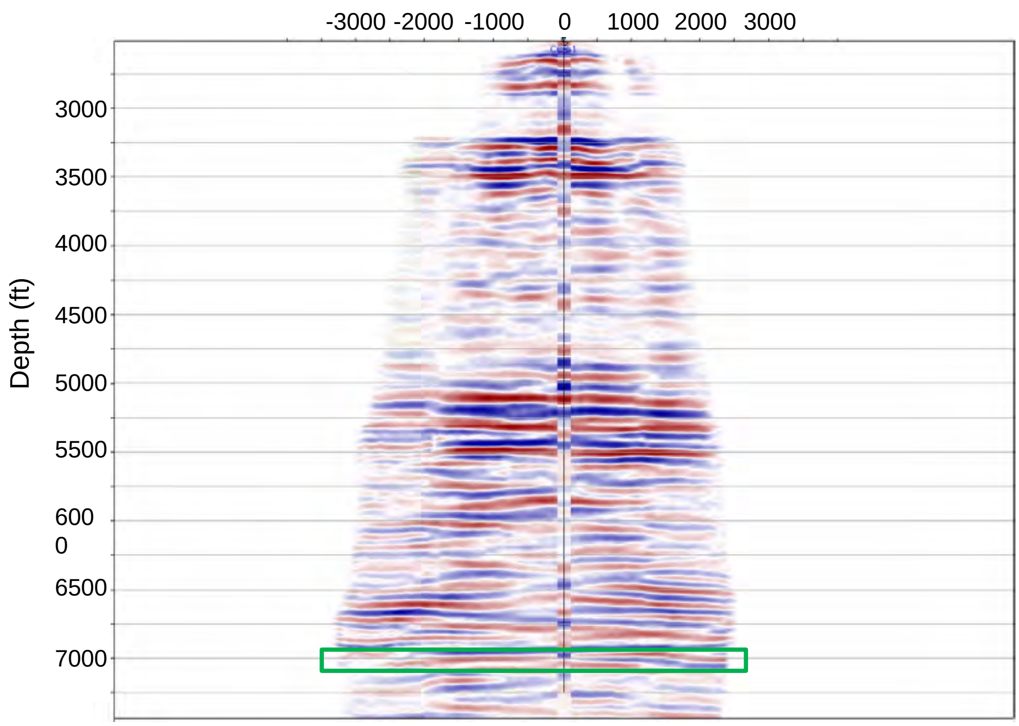


Figure 1: A 3D VSP image from IBDP. The 3D VSP images out to a radius of approximately 2500 ft at the depth of injection (green box). Courtesy of MGSC.

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6A.2.6 Surface Air and Soil Gas Monitoring

Potential Risks to USDW

Based on the injection zone depth within the Mt. Simon, the thickness of the Eau Claire Formation confining unit, and the presence of multiple secondary seals, a scenario where CO_2 comes in direct contact with the site's USDW appears highly improbable. However, to assure that groundwater resources are adequately protected, a groundwater monitoring program will be conducted at the site. The lowermost USDW is not expected to be vulnerable to contamination resulting from the injection of CO_2 into the Mt Simon Sandstone. This is in part due to the presence of multiple hydrologic seals that are barriers to upward fluid movement. Within the Illinois Basin, thick shale units function as significant regional seals. These are the Devonian-age New Albany Shale, Ordovician age Maquoketa Formation, and the Cambrian-age Eau Claire Formation. There are also many minor, thinner Mississippian- and Pennsylvanian-age shale beds that form seals for known hydrocarbon traps within the basin. Regarding overlying seal(s) integrity, all three significant seals are laterally extensive and appear, from subsurface wireline correlations, to be continuous within a 100-mile radius of the test site.

Another important detail is the fact that the lowermost seal, the Eau Claire, has no known penetrations within a 17-mile radius surrounding the site with the exception of the two sequestration-related wells at the IBDP site (CCS #1 and Verification Well #1), both of which are constructed to UIC Class VI specifications. Because the IBDP wells were recently constructed with special materials meeting UIC Class VI specifications (i.e. chrome casing and CO_2 resistant cement), their integrity is well known and documented.

The Illinois Basin has the largest number of successful natural gas storage fields in water bearing formations in the United States. These gas storage fields provide important analogs that can be used to analyze the potential for CO_2 sequestration. These analogs illustrate long-term seal integrity, injection capability, storage capacity, and reservoir continuity in the north-central and central Illinois Basin at comparable depths. Nearly 50 years of successful natural gas storage in the Mt. Simon Sandstone strongly indicated that this saline reservoir and overlying seals should provide successful containment for CO_2 sequestration.

Gas storage projects in the Illinois Basin all confirm that the Eau Claire is an effective seal in the northern and central portions of the Basin. Core analysis data from the Manlove Gas Storage Field, 45 miles to the northeast of the proposed site, show that the Eau Claire shale intervals have vertical and horizontal permeability less than 0.1 mD.

Regional cross sections in the central part of Illinois show that the Eau Claire Formation, the primary seal, is a laterally persistent shale interval above the Mt. Simon that is expected to provide a good seal. Drilling at the IBDP site shows that the Eau Claire should be approximately 500 feet thick at the IL-ICCS site (reference Section 2.5 of this application). As discussed in Section 2.5, the IL-ICCS site should have approximately 200 feet of sealing shale in the Eau Claire Formation directly above the Mt. Simon Sandstone.

The database of UIC wells with core from the Eau Claire was also used to derive seal qualities. This database shows that the Eau Claire's median permeability is 0.000026 mD and median porosity is 4.7%. At the Ancona Gas Storage Field, located 80 miles to the north of the proposed ADM site, cores were obtained through 414 feet of the Eau Claire, and 110 analyses were performed on a foot-by-foot basis on the recovered core. Most vertical permeability analyses showed values of <0.001 to 0.001 mD. Only five analyses were in the range of 0.100 to 0.871 mD, the latter being the maximum value in the data set. Thus, even the more permeable beds in the Eau Claire Formation are expected to be relatively tight and tend to act as sealing lithologies.

There are no mapped regional faults and fractures within a 25-mile radius of the ADM site. New 2D seismic reflection data did not detect any faults or adverse geologic structures in the vicinity of the proposed well site (Section 2.2). The drilling of the injection well will yield data such as time-to-depth conversions, and will be used to design and execute a comprehensive 3D seismic data volume to further ensure that no seismically resolvable faults and fractures pose a threat to the integrity of the injection site. Moreover, there are no known unplugged, abandoned wells that penetrate the confining layer (Section 5.5).

Finally, it must be noted that a portion of the injected CO_2 will be converted to carbonic acid upon contact with the brine in the injection formation, but this is not expected to significantly impact the formation lithology. This is due to brine's pH being maintained above 2.0 because of pH-buffering reactions that will occur between the acidified brine and feldspar minerals within the Mt. Simon Sandstone.

6A.2.6.2 Surface Air Monitoring Plan

Due to the limited risk of USDW endangerment by CO_2 migration as discussed in Section 6A.2.6.1, and similarly the limited risk of migration to the atmosphere, surface air monitoring is not proposed for this permit.

6A.2.6.3 Soil Gas Monitoring Plan

Due to the limited risk of USDW endangerment by CO_2 migration as discussed in Section 6A.2.6.1, and similarly the limited risk of migration to the soil, soil gas monitoring is not proposed for this permit.

6A.2.7 Periodic Review

The testing and monitoring plan shall be periodically reviewed to incorporate collected monitoring and operational data. No less frequently than every 5 years, the most recent area of review shall be reevaluated and based on this review, an amended testing and monitoring plan, or demonstration that no revision is necessary, shall be submitted to the permitting agency. Any amendments to the testing and monitoring plan approved by the permitting agency, will be incorporated into the permit, and will subject to the permit modification requirements as appropriate. Amended plans or demonstrations shall be submitted to the permitting agency:

(1) Within one year of an area of review re-evaluation; or

(2) Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the permitting agency; or

(3) When required by the permitting agency.

Figure 6A-2: Thickness of the upper Glasford aquifer (modified from Larson et al., 2003). The IL-ICCS project site within T17N, R3E is shown in red.

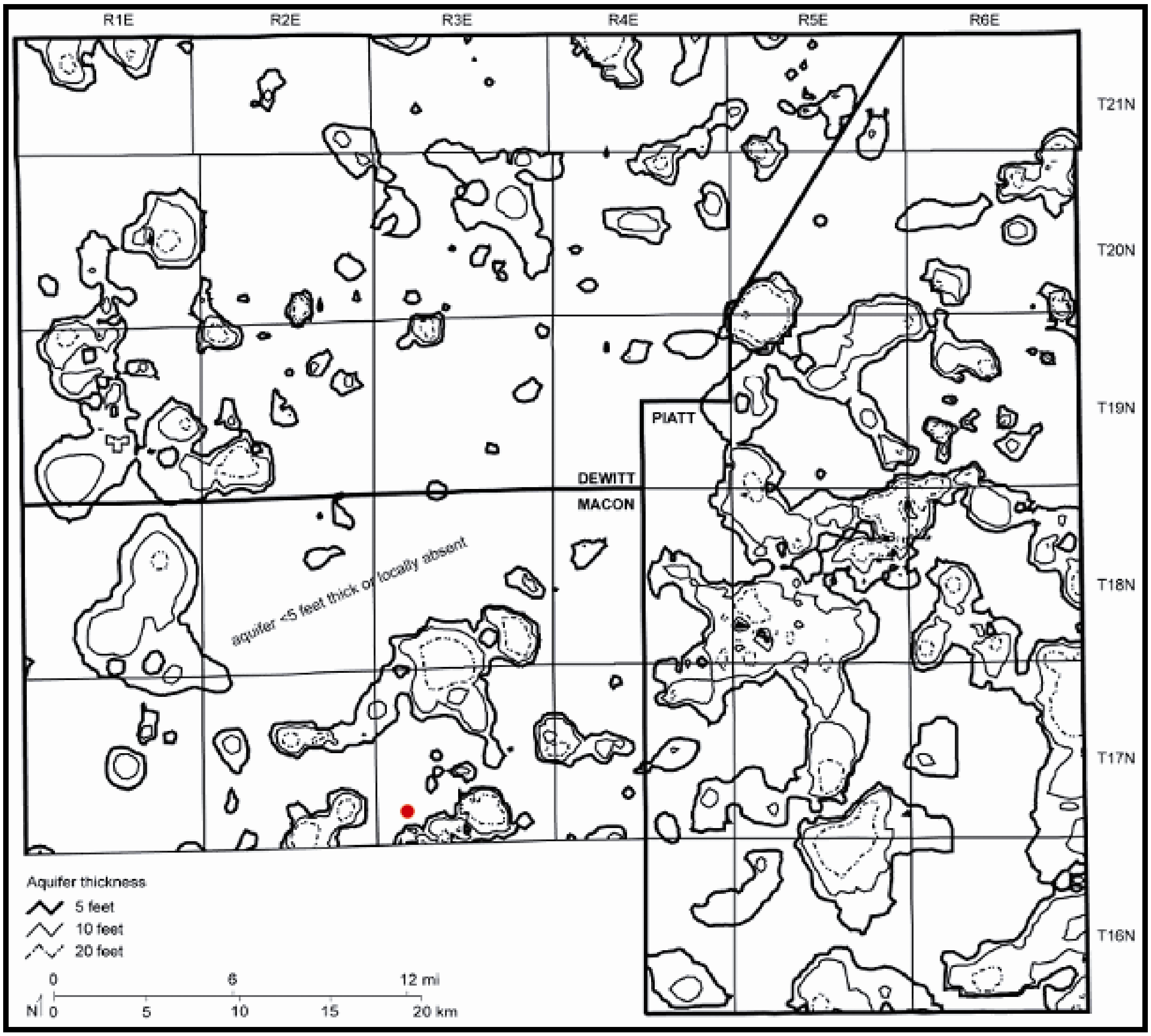
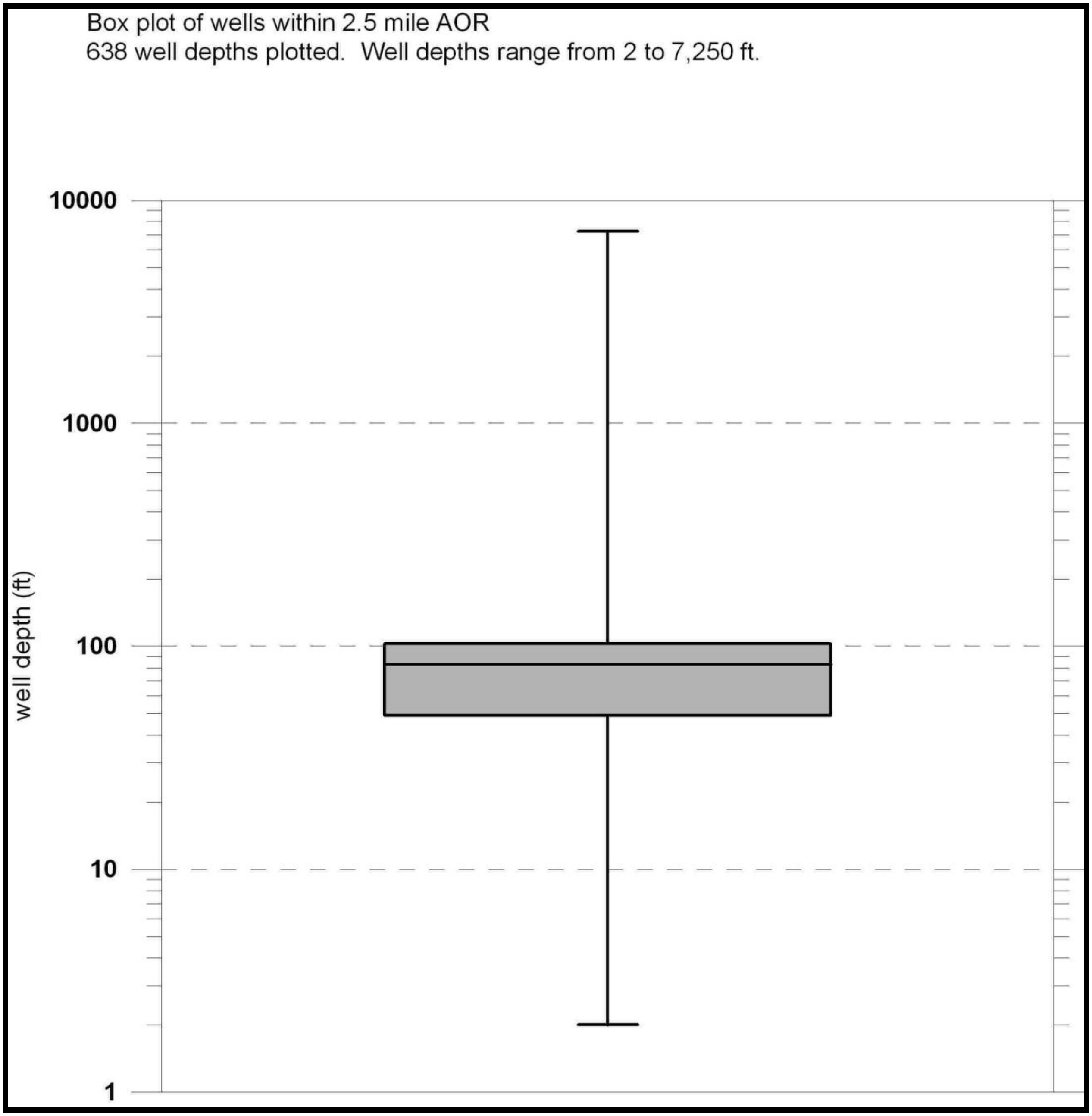


Figure 6A-3: Box plot of the water well depths within 2.5 mile radius of injection well site.



The box plot shows the distribution of the well depths. The bottom of the box marks the 25th percentile, the middle marks the median (50%) and the top marks the 75th percentile. The long whiskers mark the minimum and maximum. This graph was generated using 638 data points.

Figure 6A-4: Depth to the upper Glasford aquifer (modified from Larson et al., 2003). The IL-ICCS project site within T17N, R3E is shown in red.

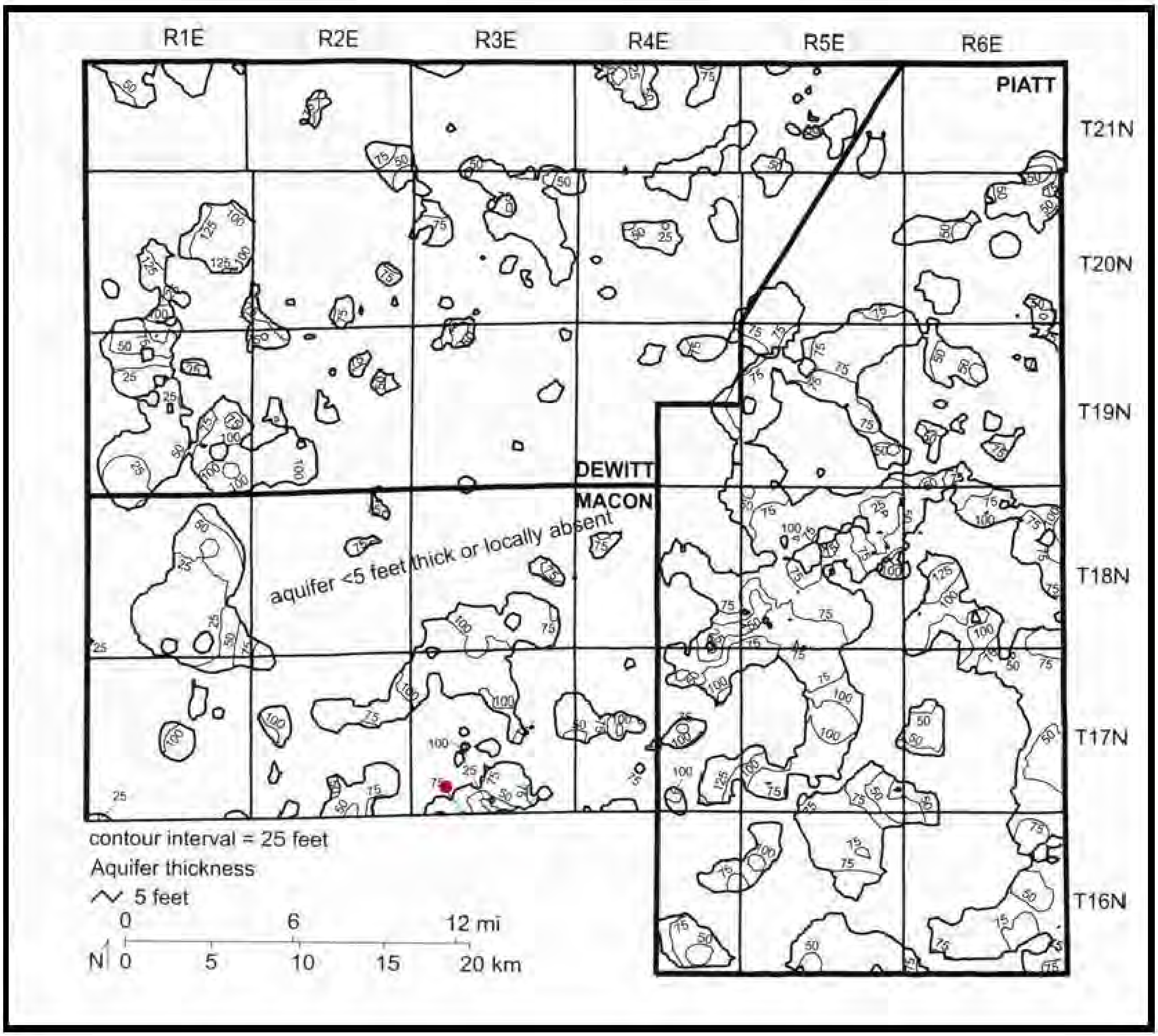


Figure 6A-5: Proposed locations of the IL-ICCS injection well and USDW monitoring wells.

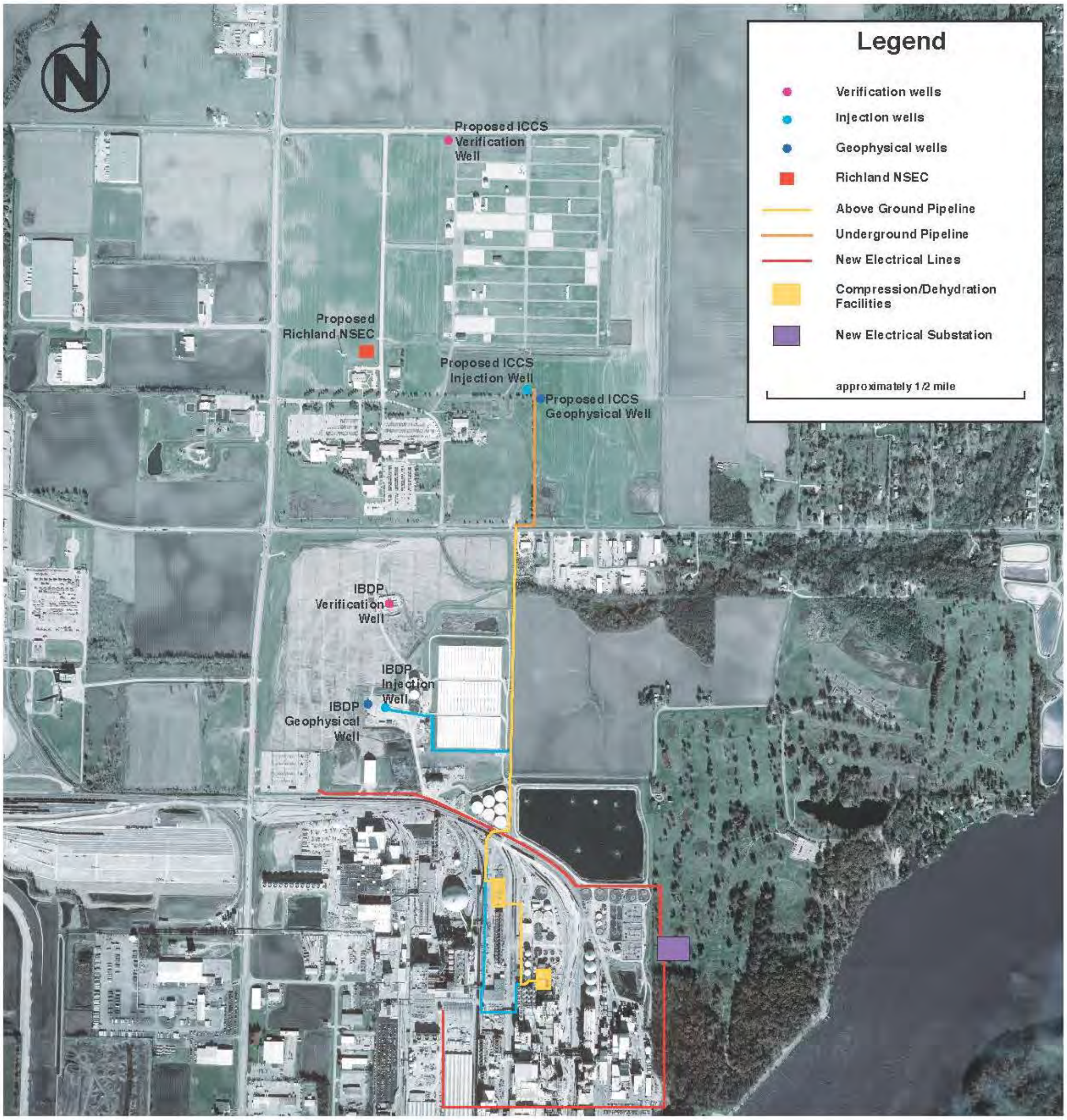


Figure 6A-6: Shallow Groundwater Well Locations.

Shallow ground water wells will include two wells within 200 feet of the injection well, one additional well within 400 feet, and a fourth compliance well within 2000 feet of the CCS #2 injection well. The precise locations of these wells are yet to be determined and will be documented in the completion report.

6A.3 Mechanical Integrity Tests During Service Life of Well

6A.3.1 Continuous Monitoring of Annular Pressure

To verify the "absence of significant leaks," the surface injection pressure, and the casing-tubing annulus pressure will be continuously monitored and recorded.

The following procedures will be used to limit the potential for any unpermitted fluid movement into or out of the annulus (see Section 3A.7.5):

i. The annulus between the tubing and the long string of casing shall be filled with brine. The brine will have a specific gravity of 1.25 and a density of 10.5 lbs/gal. The hydrostatic gradient is 0.546 psi/ft. The brine will contain a corrosion inhibitor.
ii. The surface annulus pressure will be kept at a minimum of 400 pounds per square inch (psi) at all times.
iii. The pressure within the annular space, over the interval above the packer to the confining layer, shall be greater than the pressure of the injection zone formation at all times.
iv. The pressure in the annular space directly above the packer shall be maintained at least 100 psi higher than the adjacent tubing pressure during injection. This does not include start-up and shutdown periods.

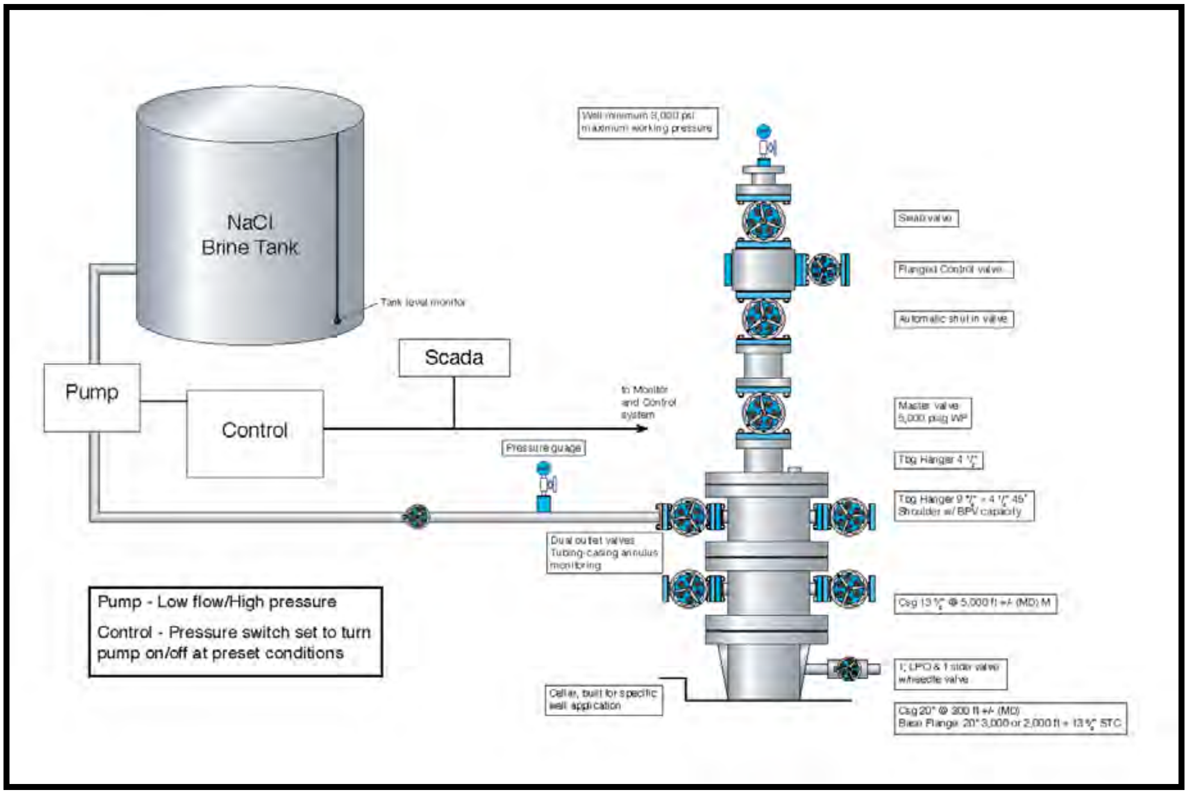
Figure 6A-7 shows the injection well annulus protection system. The annular monitoring system will consist of a continuous annular pressure gauge, a brine water storage reservoir, a low-volume/high-pressure pump, a control box, fluid volume measurement device, fluid, and electrical connections. The control box will receive pressure data from an annular pressure gauge and will be programmed to operate the pump as needed to maintain approximately 400 psi (or greater) on the annulus. A means to monitor the volume of fluid pumped into the annulus will be incorporated into the system by use of a tank fluid level gauge, flow meter, pump stroke counter or other appropriate devices.

The annulus pump will be a General Pump Co. Model 1321 (or similar device) triplex pump rated to 2,100 psi and a flow rate of 5.5 gpm. The pump will be powered by a 3.0 hp, 110/220V electric motor. Pressure will be monitored by the ADM control system gauges. The pump will be controlled by two pressure switches one for low pressure to engage the pump and the other for high pressure to shut the pump down. Anticipated range on the switches would be 400 psi or higher for the low pressure set point and 500 psi or higher for the high pressure set point. Annulus pressure will be monitored at the ADM data control system. A brine storage tank will be connected to the suction inlet of the pump. A hydrostatic tank level gauge will be installed in the brine storage tank with data fed into the ADM monitoring system. The brine in the storage tank will be the same brine as in the annulus. Any changes to the composition of annular fluid shall be reported in the next report submitted to the permitting agency.

As noted in Section 6A.2.2.2, if system communication is lost for greater than 30 minutes, project personnel will perform field monitoring of manual gauges every four hours or twice per shift for both wellhead surface pressure and annulus pressure, and record hard copies of the data until communication is restored. An example of a form for maintaining the record is included in Figure 6A-1.

Average annular pressure and fluid volumes changes will be recorded daily and reported to the permitting agency as required.

Figure 6A-7: The annular monitoring system general layout.



6A.3.2 Annual Testing

To ensure the mechanical integrity of the casing of the injection well, temperature data will be recorded at least annually across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided.

Internal Mechanical Integrity will be demonstrated through the continuous monitoring of the annular system as described in the preceding section.

6A.3.3 Other Available Testing (If Conditions Warrant)

If required due to anomalous temperature data and to verify the "absence of significant fluid movement," a Pulsed Neutron Capture / Sigma log (i.e. Schlumberger's Reservoir Saturation Tool, or RST), can be run in the injection well from the base of the injection interval through the seal and across the porous zones above the seal. An initial RST will also be run before CO_2 injection to establish a good pre-CO_2 baseline to compare the post-CO_2 logging runs. The RST cased hole can be run through tubing such that the tubing and packer do not need to be removed during logging. The RST can also provide Sigma measurement through multiple strings of casing and tubing.

The logging tools can enter the wellbore through a lubricator at the surface, so it is not necessary to kill the well with another liquid. The tubing design is such that there are no restrictions so that the appropriate cased hole logging tools (e.g. RST, Temperature, Pressure) can pass through the tubing and log the near wellbore environment behind the casing.

Testing procedures can be found in Appendix G. Annular pressure will be measured at the surface continuously to check for increases or decreases in pressure.

Details of Schlumberger's version of these tools are described below:

Pulsed Neutron Capture Logging
Reservoir Saturation Tool (RST) - Designed for reservoir complexity
Within the last decade, nearly every aspect of reservoir management has grown in complexity. What once was the exception is now routine: multiple-tubing and gravel pack completions, secondary and tertiary recovery, highly deviated wellbores, and three-phase production environments. The RSTPro* Reservoir Saturation Tool helps manage complexity by delivering reliable, accurate data. Run on the PS Platform string, with its suite of cased hole reservoir evaluation and production logging services, the RSTPro tool uses pulsed neutron techniques to determine reservoir saturation, lithology, porosity, and borehole fluid profiles. This information is used to identify bypassed hydrocarbons, evaluate and monitor reserves in mixed salinity and gas environments, perform formation evaluation behind casing, and diagnose three-phase flow independently of well deviation. Pulsed neutron technology.

An electronic generator in the RSTPro tool emits high-energy (14-meV) neutrons in precisely controlled bursts. A neutron interacts with surrounding nuclei, losing energy until it is captured. In many of these interactions, the nucleus emits one or more gamma rays of characteristic energy, which are detected in the tool by two high-efficiency GSO scintillators. High-speed digital signal electronics process and record both the gamma ray energy and its time of arrival relative to the start of the neutron burst. Exclusive spectral analysis algorithms transform the gamma ray energy and time data into concentrations of elements (relative elemental yields).

Formation sigma, porosity, and borehole salinity
In sigma mode, the RSTPro tool measures formation sigma, porosity, and borehole salinity using an optimized Dual-Burst* thermal decay time sequence. The two principal applications of this measurement are saturation evaluation, which relies on measurement accuracy, and time-lapse monitoring, where sensitivity is determined by measurement repeatability. A new degree of accuracy in the formation sigma measurement is achieved by combining high-fidelity environmental correction with an extensive laboratory characterization database. The accuracy of RSTPro formation sigma is 0.22 cu for characterized environments and has been verified in the Callisto and American Petroleum Institute industry-standard formations. Formation porosity and borehole salinity are either computed in the same pass or input by the user. Exceptional measurement repeatability makes the RSTPro tool more sensitive to minute changes in reservoir saturation during time-lapse monitoring. The gains in repeatability and tool stability are the result of higher neutron output and sensor regulation loops. At the typical logging speed of 900 ft/hr [275 m/hr] for time-lapse monitoring, RSTPro repeatability is 0.21 cu.

<u>Multifinger Imaging Tool</u>
The PS Platform* Multifinger Imaging Tool (PMIT) is a multifinger caliper tool that makes highly accurate radial measurements of the internal diameter of the tubing string. The tool is available in three sizes to address a wide range of through-tubing and casing size applications. The tool deploys an array of hard-surfaced fingers, which accurately monitor the inner pipe wall. Eccentricity effects are minimized by equal azimuthal spacing of the fingers and a special processing algorithm, and the PMIT-B tool incorporates powerful motorized centralizers to ensure effective centering force even in highly deviated intervals. The inclinometer in the tool provides information on well deviation and tool rotation. The PMIT-C tool can be fitted with special extended fingers for logging large-diameter boreholes.

Applications
- Identification and quantification of corrosion damage
- Identification of scale, wax, and solids accumulation
- Monitoring of anticorrosion systems
- Location of mechanical damage
- Evaluation of corrosion increase through periodic logs
- Determination of absolute inside diameter (ID)

6A.3.4 Ambient Pressure Monitoring

A pressure falloff test can be conducted if required during injection to calculate the ambient average reservoir pressure. At least one pressure fall-off test shall be performed every 5 years in accordance with 40 CFR 146.90(f). The availability of pressure data from Verification Well #2 and Verification Well #1 (IBDP Project) will provide alternative sources of pressure monitoring of the injection zone. At a minimum, a planned pressure falloff test will be preceded by one week of continuous CO_2 injection at relatively constant rate. The well will be shut-in for at least four days or longer until adequate pressure transient data are measured and recorded to calculate the average pressure. These data will be measured using a surface readout downhole gauge so a real-time decision on test duration can be made after the data is analyzed for average pressure. The gauges may be those used for day-to-day data acquisition or a pressure gauge will be conveyed via electric line (e-line).

Pressure Falloff Test Procedure
A pressure falloff test has a period of injection followed by a period of no-injection or shut-in.

Normal injection using the stream of CO_2 captured from the ADM facility will be used during the injection period preceding the shut-in portion of the falloff tests. The normal injection rate is estimated to be 3,000 MT/day (the last 3 years of the planned 5-year injection period). Prior to the falloff test this rate will be maintained. If this rate causes relatively large changes in bottomhole pressure, the rate may be decreased. Injection will have occurred for 10-11 months prior to this test, but there may have been injection interruptions due to operations or testing. At a minimum, one week of relatively continuous injection will precede the shut-in portion of the falloff test; however, several months of injection prior to the falloff will likely be part of the pre-shut-in injection period and subsequent analysis. This data will be measured using a surface readout downhole gauge so a final decision on test duration can be made after the data is analyzed for average pressure. The gauges may be those used for day-to-day data acquisition or a pressure gauge will be conveyed via electric line (e-line).

To reduce the wellbore storage effects attributable to the pipeline and surface equipment, the well will be shut-in at the wellhead nearly instantaneously with direct coordination with the injection compression facility operator. Because surface readout will be used and downhole recording memory restrictions will be eliminated, data will be collected at five second intervals or less for the entire test. The shut-in period of the falloff test will be at least four days or longer until adequate pressure transient data are collected to calculate the average pressure. Because surface readout gauges will be used, the shut-in duration can be determined in real-time. A report containing the pressure falloff data and interpretation of the reservoir ambient pressure will be submitted to the permitting agency within 90 days of the test. Pressure sensors used for this test will be the wellhead sensors and a downhole gauge for the pressure fall off test. Each gauge will be of a type that meets or exceeds ASME B 40.1 Class 2A (.5% accuracy across full range). Wellhead pressure gauge range will be 0-4,000 psi. Downhole gauge range will be 0- 10,000 psi.

6A.3.5 Corrosion Monitoring Plan

In order to monitor the corrosion potential of materials that will come in contact with the carbon dioxide stream, the following plan has been developed.

Sample Description
Samples of material used in the construction of the compression equipment, pipeline and injection well which come into contact with the CO_2 stream will be included in the corrosion monitoring program either by using actual material and/or conventional corrosion coupons. The samples consist of those items listed in Table 6A-2 below. Each coupon will be weighed, measured, and photographed prior to initial exposure (see Sample Monitoring section for measurement data).

Table 6A-2: List of Equipment Coupon with Material of Construction.

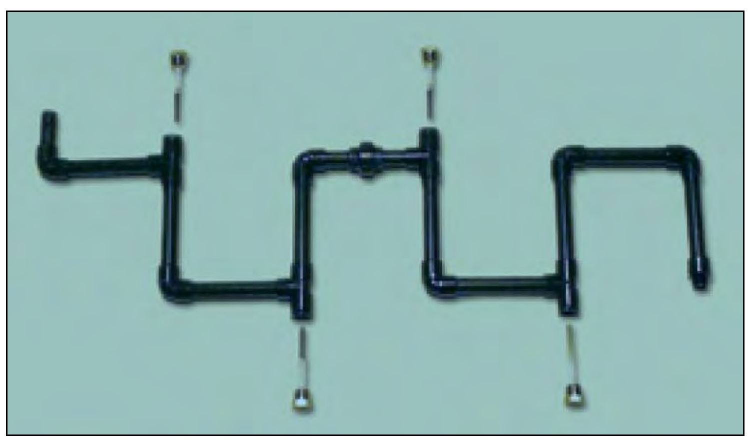
Equipment Coupon	**Material of Construction**
Pipeline	CS XPI5L-X52
Long String Casing	Chrome alloy
Injection Tubing	Chrome alloy
PS3 Mandrel	Chrome alloy
Wellhead	Chrome alloy
Packers 1	Chrome alloy
Compression Components	316L SS

Sample Exposure

Each sample will be attached to an individual holder (Figure 6A-8) and then inserted in a flow-through pipe arrangement (Figure 6A-9). The corrosion monitoring system will be located downstream of all process compression/dehydration/pumping equipment (i.e., at the beginning of the pipeline to the wellhead). To accomplish this, a parallel stream of high pressure CO_2 will be routed from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. This loop will operate any time injection is occurring. No other equipment will act on the CO_2 past this point; therefore this location will provide representative exposure of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal.

Figure 6A-8. Coupon Holder

Figure 6A-9. Flow-Through Pipe Arrangement



Sample Monitoring

The samples will be visually inspected and monitored on a quarterly basis for loss of mass, thickness, cracking, pitting, or other signs of corrosion. The sample holder will be removed from the CO_2 stream, and the samples will be removed from the holder for examination and measurements. Each coupon will be photographed and then be evaluated with the following precisions: Dimensional: 0.0001 inches; Mass: 0.0001 grams. The coupons will then be examined microscopically at a minimum of 10x power. Weights of the samples will be compared with original weights to determine if there is any weight gain or loss that would indicate degradation.

Reporting

Dimensional and mass data, along with a calculated corrosion rate (in mils/yr), will be submitted with the facility's regular operating report following the analysis.

6A.4 Contingency Plan for Well Failure or Shut In

In addition to routine or scheduled maintenance and certain system testing procedures, injection will be shut down under the following conditions (see Appendix H for Emergency and Remedial Response Plan required under 40 CFR 146.94):

- Wellhead injection pressure reaches the automatic shutdown pressure of 2,380 psig. Fracture gradient was determined to be 0.715 psi per foot, or, for mid-perforation depth of 7,025 feet, the fracturing pressure would be 5,023 psi. Using a CO_2 density of 47.31 lbs/cf with a hydrostatic gradient of 0.3285 psi/ft during injection, a wellhead pressure of 2,714 psig would be required to fracture the formation with a CO_2 of this density. The compression system has been designed and constructed for pressures up to 2,500 psig. The pipeline system has been designed and constructed for working pressure up to 2,500 psig, based on the ASME code mandated stress analysis of the pipeline components. Therefore, the surface equipment is the pressure limitation and not formation fracturing pressure.
- Injection mass flow will be continuously monitored for instantaneous flow rate and total mass injected. At no time will a mass flow rate greater than 3,300 MT be injected in a "day". The electronic control system will be configured to shut down the injection system if the mass flow rate exceeds 3,300 MT per day for a set period of time (but in no case greater than 8 hours) or if the total mass injected for the "day" equals 3,300 MT. Such an arrangement will prevent an overly-high instantaneous injection rate from continuing unabated, while also ensuring that total mass injected does not exceed permit limits. Also, it is requested that a day be defined as the period from 6:00 a.m. to 5:59 a.m. to accommodate the data archiving system in place at the Decatur Plant.

- Surface temperature varies outside the permitted range.

- Failure to maintain the tubing/casing annulus pressure (measured at the surface) at greater or equal to 400 psig.

- Failure to maintain sufficient surface annular pressure (estimated at 400 to 500 psig but may vary according to injection pressures) to maintain a minimum differential of 100 psi between the downhole annular pressure and the adjacent tubing pressure just above the packer. (The annular pressure is to be higher than the tubing pressure.) Pressures are to be calculated from surface gauge readings.

- There is reason to suspect that the injection well or cap rock integrity has been compromised via one or more of the following:

a. Failure of mechanical integrity testing as defined in the approved permit indicates CO_2 migration above the cap rock. These tests include annular pressure tests, time lapse sigma logging and temperature surveys.
b. Lowermost USDW groundwater compliance monitoring shows a statistically significant change in groundwater quality that is a direct result of CO_2 injection. Groundwater monitoring procedures shall be defined in the approved permit.

Above listed limits apply to the injection of CO_2 except during startup, testing and shutdown periods (as defined by the approved permit). At no time will injection pressures exceed the pressure that could initiate fracturing of the injection zone and/or cap rock.

If a shutdown occurs by any of the control devices, an immediate investigation will be conducted. The condition will be rectified or faulty component repaired and system will be restarted.

If the system is shutdown due to sub-surface or wellbore related issues, an investigation will be undertaken as to the cause of the event that initiated the shutdown. A series of steps can be taken to address the loss of mechanical or wellbore integrity and determine if the loss is due to the packer system or the tubing by isolating the tubing above the packer. RST logs may be run to determine well bore integrity status. In the event of a shutdown due to a subsurface related issue, adequate time will be required to develop a workover plan and to mobilize the required equipment. If a major workover is required, the well can be sealed off by placing a blanking plug in the tailpipe below the packer, and the well loaded with kill-weight brine while plans are developed as to how to best approach the workover.

6A.4.1 Persons Designated to Oversee Well Operations

A site-specific list of persons designated to oversee well operations in the event of an emergency shall be developed and maintained during the life of the project.

6A.5 Quality Assurance Plan

Data collected by the operator for testing and monitoring of the Class VI injection well will be subject to verification by an independent laboratory or, if compiled in-house, will be subject to verification using in-house quality assurance procedures.

Testing and monitoring data to be submitted to the permitting agency will be reviewed by the operator prior to submission. Any data inaccuracies will be noted and checked to determine the error source (e.g. monitoring equipment malfunction, data entry error, lab reporting error, etc.) and correct the error source as soon as possible.

6A.6 Reporting Requirements

This section is provided to satisfy the requirements of 40 CFR 146.90.

The operator shall provide required reports to the permitting agency in an approved electronic format.

Required reports will include the following;

(1) Semi-annual reports
   a. Quarterly carbon dioxide stream characteristics (physical, chemical, other);
   b. Monthly average, maximum, and minimum values for:
      i. Injection pressure;
      ii. Flow rate and mass;
      iii. Annular pressure;
   c. Any event(s) that exceed operating parameters for annular pressure or injection pressure;
   d. Any event(s) which trigger a shut-off device;
   e. Monthly volume and/or mass of carbon dioxide injected over the reporting period;
   f. Cumulative volume of carbon dioxide injected over the project life;
   g. Monthly annulus fluid volume added to the injection well.

(2) Results to be reported within 30 days:
   a. Periodic tests of mechanical integrity;
   b. Any well workover;
   c. Any other test of the injection well performed, if required by the permitting agency.

(3) Information to be reported within 24 hours of occurring:
   a. Any evidence that the carbon dioxide stream or associated pressure front has or may cause endangerment to a USDW;
   b. Any non-compliance with permit condition(s), or malfunction of the injection system, that may cause fluid migration to a USDW;
   c. Any triggering of a shut-off system;
   d. Any failure to maintain mechanical integrity;
   e. Any uncontrolled release of carbon dioxide to the atmosphere.

(4) Notification to be provided at least 30 days in advance:
   a. Any planned well workover;
   b. Any planned stimulation activities (other than stimulation for pre-operation formation testing)
   c. Any other planned test of the injection well.

Records will be retained for at least 10 years following site closure.

SECTION 6B - VERIFICATION WELL MONITORING, INTEGRITY TESTING, AND CONTINGENCY PLAN

6B.1 Fluid Sampling and Analysis

The verification well will be installed only for the purpose of monitoring subsurface conditions and will not be used for injection of CO_2. Therefore, there are no (pre-injection) waste sampling requirements associated with these wells.

6B.1.1 Sampling frequency – N/A
6B.1.2 Analysis parameters – N/A
6B.1.3 Sampling location – N/A
6B.1.4 Detailed waste analysis plan – N/A

6B.2 Monitoring Program

Refer to 6A.2 for a description of the overall monitoring program.

This section (6B) is intended to supplement section 6A by providing additional details which are specific to Verification Well #2.

One monitoring well (herein referred to as verification well) will be drilled and completed to allow observations which will measure formation pressures and help track the location of the CO_2 plume resulting from injection at nearby injection well(s). These observations will be available via various options including direct measurements of pressure and temperature, collection of samples for chemical analysis if required, and through wireline measurements such as pulsed neutron logs. This verification well, to be named Verification Well #2, will be drilled vertically and located in a position which is anticipated to be proximal to the outside edge of the CO_2 plume front at a time of 3 to 5 years after injection begins. See Section 5 for the modeling based predictions of the spatial plume front.

A multi-zone monitoring system will be deployed to allow measurement of fluid pressures and temperature, collection of fluid samples if required, and performance of standard hydrogeologic tests at and between multiple intervals. Five monitoring zones are planned in this monitoring well; these will be located throughout the Mt. Simon Sandstone. The exact location of the monitoring zones will be determined based on drilling and geologic information, obtained during the drilling of the wells.. IBDP results to date will also be used to select the zones within the Mt. Simon to be monitored. The monitoring program will be utilized to confirm the presence of annular seals between monitoring zones.

After a petrophysical review of all available data, the chosen zones will be developed by perforating short discrete intervals (e.g. 2 to 3 feet each) in the well casing. The multi-zone monitoring system will be installed inside the well casing, using hydraulically set packers to seal the annular space between the perforations and prevent fluid flow between perforations. The system is compatible with the expected site subsurface environment (brine and CO_2). Elastomers used in the packer elements will be CO_2 resistant.

6B.2.1 Recording Devices

Modular zonal management system description
The proposed multi-zone monitoring system integrates series of packers, flow control valves, and pressure/temperature measurements in modular assemblies.

A single electronic control line will be used to communicate with all of the pressure and temperature gauges. High resolution gauges will be used to monitor pressure and temperature.
System Operation
Fluid pressure measurements can be collected from each zone in the verification well simultaneously.

The primary purging and well development will be carried out prior to installation of the multi-zone monitoring system.

6B.2.2 Control and Alarm System for the Well Monitoring and Maintenance N/A

6B.2.3 USDW Monitoring in Area of Review See Section 6A.2.3

6B.2.4 Detailed Groundwater Monitoring Plan N/A

6B.2.5 Tracking Extent and Pressure of CO_2 plume See Section 6A.2.5

6B.2.6 Surface Air and and/or Soil gas monitoring See Section 6A.2.6

6B.3 Mechanical Integrity Tests During Service Life of Well

To verify the "absence of significant leaks," the downhole and surface pressures, along with the casing-tubing annulus pressure, will be monitored and recorded. Routine monitoring activities that will be used as part of the Mechanical Integrity Testing System are described below:

1) Monitoring of the pressure or the absence of pressure inside the casing/tubing annulus above the uppermost packer will be carried out continuously by means of a pressure gauge at the wellhead. An unexpected change in the annulus pressure will be investigated to ensure that it is not an indication of the loss of a top packer seal. See Section 3B.7.5.6.

   Also, see Section 6B.4 for step-by-step procedures regarding installation and removal of the multi-zone monitoring system.

a. Under normal operating conditions, monitoring of the pressure inside the tubing will be carried out continuously using a pressure gauge at the wellhead. Manual readings of the fluid level inside tubing will be collected as part of standard operating procedures for all other activities (tubing open to atmosphere). An unexpected change in the water level inside the tubing will be investigated to confirm that it is not indication of a loss of hydraulic integrity. .

2) Continuous measurement and recording of fluid pressure/temperature will be carried out using the downhole pressure probes and temperature sensors located at select monitoring zones. Automated measurement of fluid pressure and temperature is intended from each of the perforated monitoring zones. Observed differential pressures between perforated zones provide on-going confirmation of effective annular seals between monitoring zones. As part of the Mechanical Integrity Testing System, an additional pressure probe will be used to continuously measure and record fluid pressure above the uppermost packer.

3) Baseline cased-hole logs will be run prior to injection and can be run on a repeat basis if conditions warrant. The profile inside of the tubing will allow passage of cased hole logging tools [e.g. Temperature, Pulse Neutron Capture (PNC), also known as Sigma or RST]. In the event of a compromised seal where CO_2 enters the annulus, the PNC tool will be used to identify unexpected CO_2 independently of the downhole pressure/temperature measurements.

In the event that the routine monitoring activities detailed above are inconclusive, a range of additional test procedures could be employed to further investigate any data irregularities and if necessary determine an appropriate remedial action. If in-place remediation cannot be carried out, the multi-zone monitoring system can be removed. Procedures for this removal are outlined elsewhere in this permit application. (Section 6B.4 Contingency Plan)

Temperature Logging and Time Lapsed Formation Sigma Logs

To verify the "absence of significant fluid movement," time-lapse formation sigma logs can be run and data recorded across the entire interval from the deepest reachable point in the Mt. Simon to, at a minimum, the Maquoketa Formation (the lowest alternative confining zone). The initial sigma log will include temperature data and will be run before CO_2 injection to establish a pre- CO_2 baseline to compare with the post injection logging runs. Logs will be run under static conditions, presumably with tubing in the well, although valid data can and will be acquired should tubing be pulled for any unforeseen reasons. If any subsequent surveys are performed during the CO_2 injection period, the evaluation shall also include a temperature log to further detect fluid movement. The temperature log shall be run over the same intervals and at the same conditions as the sigma logs. Should either evaluation method (sigma or temperature log) detect significant fluid movement above the seal, oxygen activation logging methods may be used to further quantify the flow and aid in establishing a remediation plan. Details of Schlumberger's version of these tools are described below:

Pulsed Neutron Capture Logging

Reservoir Saturation Tool (RST) - Designed for reservoir complexity
Within the last decade, nearly every aspect of reservoir management has grown in complexity. What once was the exception is now routine: multiple-tubing and gravel pack completions, secondary and tertiary recovery, highly deviated wellbores, and three-phase production environments. The RSTPro* Reservoir Saturation Tool helps manage complexity by delivering reliable, accurate data. Run on the PS Platform string, with its suite of cased hole reservoir evaluation and production logging services, the RSTPro* tool uses pulsed neutron techniques to determine reservoir saturation, lithology, porosity, and borehole fluid profiles. This information is used to identify bypassed hydrocarbons, evaluate and monitor reserves in mixed salinity and gas environments, perform formation evaluation behind casing, and diagnose three-phase flow independently of well deviation.

An electronic generator in the RSTPro* tool emits high-energy (14-meV) neutrons in precisely controlled bursts. A neutron interacts with surrounding nuclei, losing energy until it is captured. In many of these interactions, the nucleus emits one or more gamma rays of characteristic energy, which are detected in the tool by two high-efficiency scintillators. High-speed digital signal electronics process and record both the gamma ray energy and its time of arrival relative to the start of the neutron burst. Exclusive spectral analysis algorithms transform the gamma ray energy and time data into concentrations of elements (relative elemental yields).

Formation sigma, porosity, and borehole salinity
The RSTPro* tool measures formation sigma, porosity, and borehole salinity using an optimized Dual-Burst* thermal decay time sequence. The two principal applications of this measurement are saturation evaluation, which relies on measurement accuracy, and time-lapse monitoring, where sensitivity is determined by measurement repeatability. A higher degree of accuracy in the formation sigma measurement is achieved by combining high-fidelity environmental correction with an extensive laboratory characterization database. The accuracy of RSTPro formation sigma is 0.22 cu for characterized environments and has been verified in the Callisto and American Petroleum Institute industry-standard formations. Formation porosity and borehole salinity are either computed in the same pass or input by the user. Exceptional measurement repeatability makes the RSTPro tool more sensitive to minute changes in reservoir saturation during time-lapse monitoring. The gains in repeatability and tool stability are the result of higher neutron output and sensor regulation loops. At the typical logging speed of 900 ft/hr [275 m/hr] for time-lapse monitoring, RSTPro repeatability is 0.21 cu.

Water velocity (Oxygen activation logging)
The RSTPro WFL* Water Flow Log measures water velocity by using the principle of oxygen activation. Gamma ray energy discrimination and tool shielding reduce the background from stationary activation, improving sensitivity in low-signal environments such as flow behind casing.

The cased-hole logging tools (e.g. the Reservoir Saturation Tool – RST) can pass through the tubing (since there will be no tubing restrictions smaller than 2.25") and log the near-wellbore environment behind the well casing. The cased-hole logs are not adversely affected by the multi-zone monitoring system such that the tubing does not need to be removed during the RST and other cased-hole wireline logging techniques.

6B.3.1 Continuous Monitoring of Annular Pressure

Continuous annular pressure monitoring will also be used to verify mechanical integrity of the well. The pressure data will be transmitted to the ADM control room for monitoring and will be recorded at the same frequency as the injection well data (frequency) and reported monthly. If a pressure increase greater than 100 psi over atmospheric pressure is observed, or if pressure drops below 95% of atmospheric pressure (i.e. < 14.0 psi), an alarm will be triggered and the cause will be investigated. An example of the operational monitoring data for pressure is included on Figure 6B-1 "*Example Field Log Form for Manual Verification Well Gauge Readings*". The annular space will also be checked quarterly to verify that the annulus is full; fluid will be replaced as needed. This observation will be noted in the operating report. Pressure fluctuations in the range (or possibly exceeding the range) noted above are likely to occur immediately following well construction, sampling, and well workovers but would not be indicative of well integrity issues. Notation of these events will be included in the monthly reports. In the event of a power outage, manual readings will be taken and recorded.

In addition the following section describes the mechanical integrity testing of the wellbore across the multi-level monitoring system.

The multi-zone monitoring system is designed to incorporate a high degree of quality assurance testing and verification to confirm mechanical integrity of the system and the presence of packer seals between monitoring zones

Monitoring is intended to be carried out at multiple levels within the Mt. Simon injection horizon. A monitoring program will be utilized to confirm the presence of annular seals above the uppermost monitoring zone, and particularly to document the performance of the annular seals which isolate the individual zones and also prevent the movement of fluids into the overlying stratigraphic units.

The multi-zone monitoring system is compatible with the expected site subsurface environment (brine and CO_2) and elastomers present in the System will be CO_2 resistant. Thus, loss of mechanical integrity or component failure leading to the potential for vertical migration of fluid in the annulus is not expected. However, a number of methods, including wireline and pressure and temperature measurements, will be used to monitor system integrity and to verify the absence of vertical fluid movement within the well. These methods are implemented during the multi-zone monitoring system installation and during ongoing monitoring well operations, as described below.

During the installation process, a thorough QA procedure is followed to document the system performance, including:

- testing the hydraulic integrity of each tubing joint as the tubing string is assembled, providing baseline data confirming that the assembled joint is sealed and not a pathway for vertical movement of formation fluids

- testing the hydraulic integrity of the entire tubing string once the tubing has been lowered into place, again providing baseline data confirming that the tubing string is sealed and not a pathway for vertical movement of formation fluids

After the packers have been set, fluid pressure profiles and cased-hole logging will be carried out to establish baseline conditions of the well.

6B.3.2 Annual Testing

The annulus between the long string and the tubing above the uppermost packer will be pressure tested to 300 psi for one hour with a maximum of 3% leakoff allowed (see procedure in Section 3B.7.5). This test will be performed at least once per year and results will be reported in the next operating report. Following the annual test, the remaining pressure will be bled off to atmospheric and the annular space will be shut in.

6B.3.3 Ambient Pressure Monitoring

Continuous measurement and recording of fluid pressure/temperature will be carried out using the multi-zone monitoring system, which consists of pressure probes located at select monitoring zones. Automated measurement of fluid pressure is intended from each of the perforated monitoring zones. It should also be noted that the observed differential pressures between perforated zones will provide an ongoing confirmation of effective annular seals between monitoring zones.

6B.3.4 Corrosion Monitoring Plan

Cased hole logs (Multi-finger caliper, Ultrasonic Cement Evaluation) will be run during the initial verification well completion to provide baseline measurements of the long string casing internal diameter and thickness. This will allow for a comparison to subsequent logs if conditions suggest a need to re-run logs.

6B.4 Contingency Plan for Well Failure or Shut In

If necessary, the tubing string can be retrieved from the well. While this may not be the first course of action in response to information from the integrity monitoring measurements, this option is available if required.

The verification well will be remediated under the following conditions:

1) Abnormal annular pressure readings are observed.

Following the MIT, the remaining pressure will be bled off to atmospheric and the annular space will be shut in. If a pressure increase greater than 100 psi over atmospheric pressure is observed, or if pressure drops below 95% of atmospheric pressure (i.e. < 14.0 psi), an alarm will be triggered and the cause will be investigated.

2) Abnormal pressure / water levels are observed inside the tubing.

If there are pressures measured 100 psi over static levels or if pressure drops below 95% of atmospheric pressure (i.e. < 14 psi) inside the tubing an alarm will be triggered. Further investigation will be conducted as to the cause of the abnormal pressure reading, and remediation planned.

3) Suspicion that the well integrity has been compromised.

4) Surface equipment has been damaged.

If any of above should occur, steps will be taken to identify and correct any equipment deficiencies. Many interventions can be carried out using the multi-zone monitoring system to affect repairs and re-establish well bore integrity. Only if none of these interventions were successful then plans to remove the system from the well would be put in place. If required, retrieval of the tubing string would be done with BOPs in place according to the following summarized procedure:

1) Secure well until a workover rig and support equipment can be mobilized. Notify permitting agency of planned workover.

2) Rig up workover rig with pump and tank. Bleed down any pressure. Fill both tubing and annulus with kill weight fluid.

3) Begin to release all packers. Open appropriate sliding sleeve(s), and attempt to circulate fluid at very low rate. Close sliding and proceed to next packer.

4) When all packers are released, remove plug (if a plug was placed in bottom of string) and attempt to slowly circulate the well with kill weight fluid.

5) Prepare to remove tubing string from the well while carefully keeping the hole full of kill-weight brine. Pull tubing slowly as to not over-pull the designed strength of the tubing.

6) Remove tubing from the well and examine to identify the cause of the anomalous pressure.

Upon removal, a decision will be made as to whether to repair and replace or to plug and abandon the well.

The plan for the verification well includes but is not limited to the following:

1) A modified master and single wing wellhead assembly. Since these wells are not injection wells, wing valves will not have an automatic shut-down system but will employ manual gate valve assemblies which will be closed during normal operations.

2) All annuli will have pressure gauges installed. Gauges to be 0 to 150 psi operating range.

3) Under normal operating conditions, the well is essentially shut in and will be open only for testing, sampling, and maintenance. See Figure 3B-4 for wellhead diagram.

In the event of a power outage, manual readings of the pressure in the tubing and annulus will be taken and recorded every four hours until power is restored. Note that in the event of a power outage, the injection well will be shut in.

6B.4.1 Persons Designated to Oversee Well Operations

A site-specific list of persons designated to oversee well operations in the event of an emergency shall be developed and maintained during the life of the project.

6B.5 Quality Assurance Plan   See Section 6A.5

6B.6 Reporting Requirements   See Section 6A.6

Figure 6B-1. Example Field Log Form for Manual Verification Well Gauge Readings

FIELD LOG – INJECTION / VERIFICATION WELLS
(For back up field data collection in the event of power outage or other data transmission loss from automated gauges – see "*Instructions"*)

USEPA Site #1150155136 – Macon County Archer Daniels Midland – Corn Processing Carbon Sequestration Injection and Verification Wells	Permit No. Well No. UIC Log #

ADM Supervisor: ____
Readings Taken by: Name:____________________________________
Phone:____________________________________

Check Box(es) Above Failed Instrument(s) ➔						
DATE	**TIME**	**Injection Wellhead Pressure** PIT-009 (psig)	**Injection Annulus Pressure** PIT-014 (psig)	**Verification Tubing Pressure** (psig)	**Verification Annulus Pressure** (psig)	**INITIALS**

INSTRUCTIONS – *Within 30 minutes of a communication loss, manual readings of the pressure in the tubing and annulus of both wells will be taken and recorded, and continued every 4 hours thereafter until communication is restored.*

SECTION 8A - INJECTION WELL PLUGGING & ABANDONMENT PROCEDURES

This section is provided to satisfy the requirements of 40 CFR 146.92.

8A.1 Description of Plugging Procedures

Upon completion of the project, or at the end of the life of the CCS #2 injection well, the well will be plugged and abandoned to meet all applicable requirements. The need to abandon the well prior to any injection (i.e. during construction) is also a possibility. The plug procedure and materials will be designed to prevent any unwanted fluid movement and to protect any USDWs. The well plugging procedure and design will be updated in the well plugging plan based on any new information gained during well construction and testing. The final plugging plan will be developed after collaboration and interaction with the UIC Program Director; however, to fulfill permit requirements, we propose the preliminary plan which follows.

8A.1.1 Abandonment during Construction

Abandonment during well construction, while sections of the wellbore are uncased could take place while: (1) drilling the surface hole (≤350 ft), (2) drilling intermediate hole (≤5,300 ft), or (3) drilling long-String hole (≤7,500 ft).

During each scenario, the drill string (drill collars, drill pipe, and drill bit) represents the most likely risk for losing and leaving equipment in the hole. Although unlikely, it is possible that logging tools, a core barrel, or other piece of equipment can get stuck and be left in the hole. Every attempt will be made to recover all portions of the string or other equipment prior to abandonment.

If equipment cannot be retrieved and must be abandoned in the wellbore, no unique plugging procedure should be required and the plugs will be placed as specified in the plugging plan. Plug placement will depend upon depth of the hole, the geology and the depth that the equipment was lost in the well. If the well has not penetrated or is not within 100 feet of the caprock, then typically plugging during construction would require placing plugs across any zones capable of producing fluid and at the previous casing shoe. A surface plug will be set and the well filled with drilling mud between the plugs. If the caprock has been penetrated when the well is judged to be lost, the well will be plugged using CO_2-resistant cement from TD to 1,000 feet above the caprock seal using the balanced plug method. This may require setting multiple plugs. If this occurs, each plug will be verified before moving to the next.

If a radioactive logging source is lost in the hole (e.g. a density and/ or neutron porosity logging source), current Nuclear Regulatory Commission (NRC) regulations will be followed. A 300-foot red cement plug will be placed immediately above the lost logging tool. An angled kick-plate will be placed above this plug to divert any subsequent drilling that may coincidentally enter this wellbore. Current NRC regulations require that the surface casing remain extended above the ground surface with an informative ground plate welded to the pipe. The plate includes information to identify what is in the hole. Depending upon where in the well the radioactive source is lost, plugging above the kick-plate will proceed as described above.

Plug Placement Method: The method for placing the plugs in CCS #2 will be the "Balanced Plug" method. This is a basic plug spotting process that is generally considered more efficient and is consistent with best industry practices.

8A.1.2 Abandonment after Injection

After injection has ceased, the well will be flushed with a kill weight brine fluid. A minimum of three tubing volumes will be injected without exceeding fracture pressure. Bottom hole pressure measurements will be made and the well will be logged to ensure mechanical integrity outside the casing prior to plugging. If a loss of mechanical integrity is discovered, it will be repaired using the squeeze cementing method prior to proceeding with the plugging operations. Detailed plugging procedure is provided in Section 8A.1.4 below. All casing in this well will be cemented to surface and will not be retrievable at abandonment. After injection, the injection tubing and packer will be removed. If the tubing and packer cannot be released, an electric line with tubing cutter will be used to cut off the tubing above the packer and the packer will be left in the well. After the tubing and packer are removed, the balanced-plug placement method will be used to plug the well. If the tubing has to be cut and the packer left in the well, the cement retainer method will be used for plugging the injection formation below the abandoned packer.

8A.1.3 Type and Quantity of Plugging Materials, Depth Intervals

The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction. Well cementing software (e.g. Schlumberger's CemCade) will be used to model the plugging and aid in the plug design. The cements used for plugging will be tested in the lab prior to plug placement and both wet and dry samples of each plug will be collected during plugging to ensure quality of the plug.

All of the casing strings will be cut off at least 3 feet below the surface, below the plow line. A blanking plate with the required permit information will be welded to the top of the cutoff casing.

8A.1.4 Detailed Plugging and Abandonment Plan

8A.1.4.1 Notifications, Permits, and Inspections (Prior to Workover or Rig Movement).

Notifications, permits, and inspections are the same for plugging and abandonment during construction or post-injection. The procedure is:

1) Notify the regulatory agency at least 60 days prior to commencing plugging operations. (Note that this timeline will not apply for plugging and abandonment during well construction.) Provide updated plugging plan, if applicable. Ensure proper notifications have been given to all regulatory agencies for rig move.
2) Ensure that the plugging procedure has been reviewed and agreed upon by regulatory agency.
3) Ensure that the following steps are performed prior to well plugging:
    a. The injection well is flushed with a buffer fluid;
    b. The bottomhole reservoir pressure will be measured;

    c. A final external mechanical integrity test will be completed.
    d. Plugging procedure has been reviewed and agreed upon by regulatory agency.
4) Ensure in advance that a pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks & ancillary equipment to perform P&A operations. Notify all key third parties of expected work scope, and ensure third party contracts for work are in place prior to move in.
5) Have copies of all government permits prior to initiating operations and maintain on location at all times. Check to see if conditions of approval have been met.
6) Make sure partners (U.S. DOE, EPA and ADM) approvals have been obtained, as applicable.

A site-specific list of facility contacts will be developed and maintained during the life of the project.

8A.1.4.2 Volume Calculations

Volumes will be calculated for specific abandonment wellbore environment based on desired plug diameter and length required. Volume calculations are the same for plug and abandonment during construction and post-injection.

1) Identify the following based on the geology and hole conditions:
    a. Length of the cement plug required.
    b. required setting depth of base of plug.
    c. Volume of spacer to be pumped ahead of the slurry.

2) Determine the following:
    a. Number of sacks of cement required.
    b. Volume of spacer to be pumped behind the slurry to balance the plug.
    c. Plug length before the pipe is withdrawn.
    d. Length of mud freefall in drill pipe.
    e. Displacement volume required to spot the plug.

8A.1.4.3 Plugging and Abandonment Procedure for "During Construction" Scenario:

Pumping the Cement Job

1. Trip in Hole (TIH) to the desired depth (drill pipe tags the base of the desired plug depth).

2. Shut down circulating trip tank on wellbore.

3. Break circulation and condition mud as required. Circulate at least until the pit levels stabilize.

4. Mix and pump cement and spacers.

5. Displace with the predetermined mud volume.

6. Shut down cementing unit and allow mud to freefall.

7. Near the end of the freefall, begin pulling out. Check to verify if we are pulling dry or wet. Slowly pull the drill string out of the plug and continue trip out of hole (TOH) until 300 ft +/- above the top of the plug. Slowly pump 5-10 bbls to clear the drill pipe.

8. Waiting on cement (WOC) minimum 12 hours, and TIH to tag the plug. If the plug will hold 5-10K lbs weight, pull up, circulate 1-2 stands above and continue with next plug.

9. After placing all plugs, pull out of hole (POOH) laying down all drill pipe.

10. Cut off all casings below the plow line (or per local, state or regulatory guidelines), dump 2-5 sacks of neat cement, and weld plate on top of casing stub. Place marker if required.

11. After rig is released, restore site to original condition as possible or per local, state or federal guidelines.

12. Complete plugging forms and send in with charts and all lab information to the regulatory agency as required by permit. Plugging report shall be certified as accurate by ADM and plugging contractor, and shall be submitted within 60 days after plugging is completed.

<u>8A.1.4.4 Plugging and Abandonment Procedure for "End of Project" Scenario:</u>

1. Notify the regulatory agency at least 60 days before commencing operations and provide updated plugging plan, if applicable.

2. Move-in (MI) Rig onto CCS #2 and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor prior to MI.

3. Conduct and document a safety meeting.

4. Open up all valves on the vertical run of the tree and check pressures.

5. Test the pump and line to 2,500 psi. Fill casing with kill weight brine (9.5 ppg). Bleeding off occasionally may be necessary to remove all air from the system. Test casing annulus to 1000 psi. If there is pressure remaining on tubing rig to pump down tubing and inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead then nipple up blowout preventers (NU BOP's). Monitor casing and tubing pressures.

6. If the well is not dead or the pressure cannot be bled off of tubing, rig up (RU) slickline and set plug in lower profile nipple below packer. Circulate tubing and annulus with kill weight fluid until well is dead. After well is dead, ND tree. NU BOP's and perform a function test. BOP's should have appropriate sized single pipe rams on top and blind rams in the bottom ram for tubing. Test pipe rams and blind rams to 250 psi low, 3,000 psi high. Test annular preventer to 250 psi low and 3,000 psi high. Test all TIW's,

IBOP's choke and kill lines, and choke manifold to 250 psi low and 3,000 psi high. NOTE: Make sure casing valve is open during all BOP tests**.** After testing BOPs pick up tubing string and unlatch seal assembly from seal bore. Rig slick line and lubricator back to well and remove X- plug from well. Rig to pump via lubricator and circulate until well is dead.

7. POOH with tubing laying it down. NOTE: Ensure that the well is over-balanced so there is no backflow due to formation pressure and there are at least 2 well control barriers in place at all times.

   Contingency: If unable to pull seal assembly, RU electric line and make cut on tubing string just above packer. Note: Cut must be made above packer at least 5-10 ft MD.

8. If successful pulling seal assembly, then pick up workstring and TIH with Quantum packer retrieving tools. If tubing was cut in previous step then skip this step. Latch onto Quantum packer and pull out of hole laying down same. If unable to pull the Quantum packer, pull the work string out of hole and proceed to next step. Assuming the tubing can be pulled with the packer without issues, run CBL, casing caliper, RST and/ or USIT to assist in assessing wellbore mechanical integrity leakage around the wellbore above the caprock. If problems are noted, update cement remediation plan (if needed) and execute prior to plugging operations. TIH with work string to TD. Keep the hole full at all times. Circulate the well and prepare for cement plugging operations.

9. The lower section of the well will be plugged using CO_2 resistant cement from TD around 7000ft to around 1000ft above the top of the Eau Claire Formation (to approximately 4000 ft). This will be accomplished by placing plugs in 500 ft increments. Using a density of 15.9 ppg slurry with a yield of 1.11 cf/sk, approximately 1333 sacks of cement will be required. Actual cement volume will depend upon actual weight of the casing within the plugged zone as well as the length of plug set. This will require at least six plugs of 500 feet in length. No more than two plugs will be set before cement is allowed to set and plugs verified by setting work string weight down onto the plug. (Calculations: Assume 47 lb/ft casing for this interval 3000ft x .4110 cu ft/ft x 1.20/ 1.11 cu ft/sk = 1333 sacks

10. Circulate the well and ensure it is in balance. Place tubing just above cement top from previous day. Mix and spot 500 ft balanced plug in 9 5/8 inch casing (approximately 180 sacks Class A/H mixed at 15.9 ppg with yield 1.18 cu ft/sk)). Pull out of plug and reverse circulate tubing. Repeat this operation until a total of 8 plugs have been set. If plugs are well balanced then the reverse circulation step can be omitted until after each third plug. Lay down work string while pulling from well. If rig is working daylights only then pull 10 stands and rack back in derrick and reverse tubing before shutting down for night. After waiting overnight, trip back in hole and tag plug and continue. After ten plugs have been set pull tubing from well and shut in for 12 hours. Trip in hole with tubing and tag cement top. Calculate volume for final plug. Pull tubing back out of well. Nipple down BOPs and cut all casing strings below plow line (min 3 feet below ground level or per local policies/standards and ADM requirements). Trip in well and set final cement plug.

Total of approximately 1443 sacks total cement used in all remaining plugs above 4000 feet. Lay down all work string, etc. Rig down all equipment and move out. Clean cellar to where a plate can be welded with well name onto lowest casing string at 3 feet, or as per permitting agency directive. (Calculations assume 40#/ft casing and no excess because this section is inside the intermediate casing 4000 ft x .4257 cu ft/ft / 1.18 cu ft/sk = 1443 sacks

11. Complete plugging forms and send in with charts and all lab information to the regulatory agency as required by permit. Plugging report shall be certified as accurate by ADM and plugging contractor, and shall be submitted within 60 days after plugging is completed.

SECTION 8B - VERIFICATION WELL PLUGGING & ABANDONMENT PROCEDURES

8B.1 Description of Plugging Procedures

Upon completion of the project, or at the end of the life of Verification Well #2, the well will be plugged and abandoned to meet all applicable requirements. The need to abandon the well prior to any injection (i.e. during construction) is also a possibility. The plug procedure and materials will be designed to prevent any unwanted fluid movement and to protect any USDWs. The well plugging procedure and design will be updated in the well plugging plan based on any new information gained during well construction and testing. The final plugging plan will be developed after collaboration and interaction with the UIC Program Director; however, to fulfill permit requirements, we propose the preliminary plan which follows.

8B.1.1 Abandonment during Construction

Abandonment during well construction, while sections of the wellbore are uncased could take place while: (1) drilling the surface hole (≤350 ft), (2) drilling intermediate hole (≤5,300 ft), or (3) drilling long-String hole (≤7,500 ft).

During each scenario, the drill string (drill collars, drill pipe, and drill bit) represents the most likely risk for leaving equipment in the hole. Although unlikely, it is possible that a logging tool, core barrel, or other piece of equipment can get stuck and be left in the hole. Every attempt will be made to recover all portions of the string or other equipment prior to abandonment.

If equipment cannot be retrieved and must be abandoned in the wellbore, no unique plugging procedure should be required and the plugs will be placed as specified in the plugging plan. Plug placement will depend upon depth of the hole, the geology and the depth that the equipment was lost in the well. If the well has not penetrated or is not within 100 feet of the caprock, then typically plugging during construction would require placing plugs across any zones capable of producing fluid and at the previous casing shoe. A surface plug will be set and the well filled with drilling mud between the plugs. If the caprock has been penetrated when the well is judged to be lost, the well will be plugged using CO_2-resistant cement from TD to 1,000 feet above the caprock seal using the balanced plug method. This may require setting multiple plugs. If this occurs, each plug will be verified before moving to the next.

If a radioactive logging source is lost in the hole (e.g. a density and/ or neutron porosity logging source), current Nuclear Regulatory Commission (NRC) regulations will be followed. A 300-foot red cement plug will be placed immediately above the lost logging tool. An angled kick-plate will be placed above this plug to divert any subsequent drilling that may coincidentally enter this wellbore. Current NRC regulations require that the surface casing remain extended above the ground surface with an informative ground plate welded to the pipe. The plate includes information to identify what is in the hole. Depending upon where in the well the radioactive source is lost, plugging above the kick-plate will proceed as described above.

Plug Placement Method: The method of placing the plugs in Verification Well #2 is the "Balanced Plug" method. This is a basic plug spotting process that is generally considered more efficient and is consistent with best industry practices.

8B.1.2 Abandonment at End of project

After injection has ceased, the well will be flushed with a kill weight brine fluid. A minimum of three tubing volumes will be injected without exceeding fracture pressure. Detailed plugging procedure is provided in Section 8B.1.4 below. All casing in this well will be cemented to surface and will not be retrievable at abandonment. After injection ceases and after the appropriate post-injection monitoring period is finished, the completion equipment will be removed from the well.

8B.1.3 Type and Quantity of Plugging Materials, Depth Intervals

The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction. Well cementing software (e.g. Schlumberger's CemCade) will be used to model the plugging and aid in the plug design. The cements used for plugging will be tested in the lab prior to plug placement and both wet and dry samples will be collected during plugging for each plug to ensure quality of the plug.

All of the casing strings will be cut off at least 3 feet below the surface, below the plow line. A blanking plate with the required permit information will be welded to the top of the cutoff casing.

8B.1.4 Detailed Plugging and Abandonment Procedures

8B.1.4.1 Notifications, Permits, and Inspections (Prior to Workover or Rig Movement).

Notifications, permits, and inspections are the same for plugging and abandonment during construction and post-injection.

1) Notify the regulatory agency at least 60 days prior to commencing plugging operations. (Note that this timeline will not apply for plugging and abandonment during well construction.) Provide updated plugging plan, if applicable. Ensure proper notifications have been given to all regulatory agencies for rig move.
2) Ensure that the plugging procedure has been reviewed and agreed upon by regulatory agency.
3) Ensure in advance that a pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks & ancillary equipment to perform P&A operations. Notify all key third parties of expected work scope, and ensure third party contracts for work are in place prior to move in.
4) Have copies of all government permits prior to initiating operations and maintain on location at all times. Check to see if conditions of approval have been met.
5) Make sure partners (U.S. DOE, EPA and ADM) approvals have been obtained, as applicable.

A site-specific list of facility contacts will be developed and maintained during the life of the project.

8B.1.4.2 Volume Calculations

Volumes will be calculated for specific abandonment wellbore environment based on desired plug diameter and length required. Volume calculations are the same for plug and abandonment during construction and post-injection.

1) Choose the following:
    a. Length of the cement plug desired.
    b. Desired setting depth of base of plug.
    c. Amount of spacer to be pumped ahead of the slurry.

2) Determine the following:
    a. Number of sacks of cement required.
    b. Volume of spacer to be pumped behind the slurry to balance the plug.
    c. Plug length before the pipe is withdrawn.
    d. Length of mud freefall in drill pipe.
    e. Displacement volume required to spot the plug.

8B.1.4.3 Plugging and Abandonment Procedure for "During Construction" Scenario:

Pumping the Cement Job

1. Trip in Hole (TIH) to the desired depth (drill pipe tags the base of the desired plug depth).

2. Shut down circulating trip tank on wellbore.

3. Break circulation and condition mud as required. Circulate at least until the pit levels stabilize.

4. Mix and pump cement and spacers.

5. Displace with the predetermined mud volume.

6. Shut down cementing unit and allow mud to freefall.

7. Near the end of the freefall, begin pulling out. Check to verify if we are pulling dry or wet. Slowly pull the drill string out of the plug and continue trip out of hole (TOH) until 300 ft +/- above the top of the plug. Slowly pump 5-10 bbls to clear the drill pipe.

8. Waiting on cement (WOC) minimum 12 hours, and TIH to tag the plug. If the plug will hold 5-10,000 lbs weight, pull up, circulate 1-2 stands above and continue with next plug.

9. After placing all plugs, pull out of hole (POOH) laying down all drill pipe.

10. Cut off all casings below the plow line (or per local, state or regulatory guidelines), dump 2-5 sacks of neat cement, and weld plate on top of casing stub. Place marker if required.

11. After rig is released, restore site to original condition as possible or per local, state or federal guidelines.

12. Complete plugging forms and send in with charts and all lab information to the regulatory agency as required by permit. Plugging report shall be certified as accurate by ADM and shall be submitted within 60 days after plugging is completed.

8B.1.4.4 Possible Plugging and Abandonment Procedure for "End of Project" Scenario:

At the end of the serviceable life of the verification well, the well will be plugged and abandoned. In summary, the plugging procedure will consist of removing all components of the completion system and then placing cement plugs along the entire length of the well. At the surface the well head will be removed and casing cut off 3 feet below surface. A detailed procedure follows:

1. Move in workover unit with pump and tank.

2. Fill both tubing and annulus with kill weight brine.

3. Nipple down well head and nipple up BOPs.

4. Remove all completion equipment from well. This will require deflating the Westbay packers and removing all Westbay equipment from the well.

5. Keep hole full with workover brine of sufficient density to maintain well control.

6. Pick up 2 7/8" tbg work string (or comparable) and trip in hole to PBTD.

7. Circulate hole two wellbore volumes to ensure that uniform density fluid is in the well.

8. The lower section of the well will be plugged using CO2 resistant cement from TD around 7000ft to around 1000ft above the top of the Eau Claire formation (to approximately 4000 ft). This will be accomplished by placing plugs in 500 ft increments. Using a density of 15.9 ppg slurry with a yield of 1.11 cf/sk, approximately 360 sacks of cement will be required. (3000 ft X .1305 X cu ft/ft x 1.2 excess / 1.11 cf/sk = 423 sacks) Actual cement volume will depend upon actual weight of the casing within the plugged zone. This will require at least six plugs of 500 feet in length. No more than two plugs will be set before cement is allowed to set and plugs verified by setting work string weight down onto the plug.

9. Pull ten stands of tubing (600 ft) out and shut down overnight to wait on cement curing

10. After appropriate waiting period, TIH ten stands and tag the plug. Resume plugging procedure as before and continue placing plugs until the last plug reaches the surface.

11. Nipple down BOPs.

12. Remove all well head components and cut off all casings below the plow line.

13. Finish filling well with cement from the surface if needed. Total of approximately 442 sacks total cement used in all remaining plugs above 4000 feet (4000 ft X .1305 cu ft/ft / 1.18 cu ft/sk = 442 sks) . Cement calculations based on using Class A cement from 4000 ft back to surface with a density of 15.6 ppg and a yield of 1.18 cu ft /sk. Lay down all work string, etc. Clean cellar to where a plate can be welded with well name onto lowest casing string at 3 feet, or as per permitting agency directive.

14. If required, install permanent marker back to surface on which all pertinent well information is inscribed.

15. Fill cellar with topsoil.

16. Rig down workover unit and move out all equipment. Haul off all workover fluids for proper disposal.

17. Reclaim surface to normal grade and reseed location.

18. Complete plugging forms and send in with charts and all lab information to the regulatory agency as required by permit. Plugging report shall be certified as accurate by ADM and shall be submitted within 60 days after plugging is completed.

Note: 7,000 ft 5 ½” 17 #/ft (7000 ft X .1305 cu ft/ft = 914 cu ft) casing requires an estimated 914 cubic feet of cement to fill, 14 plugs.

Approximately five days required from move in to move out, depending on the operations at hand and the physical constraints of the well, weather, and other conditions.

SECTION 8C - GEOPHYSICAL MONITORING WELL PLUGGING & ABANDONMENT PROCEDURES

As the geophysical monitoring well does not penetrate the cap rock above the Mt. Simon Sandstone,
but will have open perforations in the St. Peter formation the well will be plugged using the cement squeeze method sealing the well from the St. Peter formation to surface with cement.

8C.1 Description of Plugging Procedures

At the end of the serviceable life of the well, the well will be plugged and abandoned utilizing the following procedure:

1. Notify the permitting agency of abandonment at least 60 days prior to plugging the well.

2. Nipple down well head and connect cement pump truck to 4 ½ inch casing. Establish injection rate with fresh water. Mix and pump 247 sacks Class A cement (15.9 ppg). Slow injection rate to ½ bbl/min as cement starts to enter St. Peter perforations. Continue squeezing cement into formation until a squeeze pressure of 500 psi is obtained. Monitor static cement level in casing for 12 hours and fill with cement if needed. Plan to have 50 sacks additional cement above calculated volume on location to top out if needed. (3450 ft X .0873 cu ft/ft / 1.18 cu ft/sk = 255 sacks)

3. Cut off all well head components and cut off all casings below the plow line.

4. Install permanent marker at surface, or as required by the permitting agency.

5. Reclaim surface to normal grade and reseed location.

APPENDIX E - Materials Analysis Plan

1.0 Purpose

The purpose of this document is to provide a plan for sampling and analysis of carbon dioxide destined for sequestration at the ADM Decatur location.

2.0 Parameters and Rationale

The CO2 will typically be analyzed for the following constituents (the list of parameters to be analyzed may be altered as experience provides a clearer picture of the constituents of concern):

- CO_2 Identification (% v/v)
- Water Vapor, Moisture (ppm v/v)
- Oxygen (ppm v/v)

<u>Volatile Sulfur Compounds (VSC, ppm v/v)</u>

- Hydrogen Sulfide (H_2S)
- Sulfur Dioxide (SO_2)

<u>Volatile Oxygenates (VOX, ppm v/v)</u>

- Acetaldehyde
- Ethanol

3.0 Test Methods

Samples will be analyzed by a third party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization.

4.0 Sampling Methods

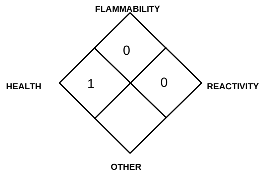
Grab samples will be collected in a tedlar bag from a sample port located downstream of the Primary Fermentation scrubber and the dehydration and compression station, but prior to the injection wellhead.

5.0 Frequency of Analysis

Samples will be collected and analyzed once every calendar quarter.

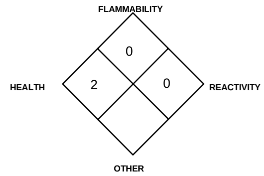
CARBON DIOXIDE GAS

NFPA RATING



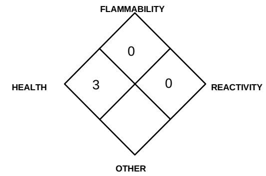
CARBON DIOXIDE SOLID

NFPA RATING



CARBON DIOXIDE LIQUEFIED

NFPA RATING



MATERIAL SAFETY DATA SHEET

Prepared to U.S. OSHA, CMA, ANSI and Canadian WHMIS Standards

PART I *What is the material and what do I need to know in an emergency?*

1. PRODUCT IDENTIFICATION

CHEMICAL NAME; CLASS: **CARBON DIOXIDE - CO_2, GASEOUS**
CARBON DIOXIDE - CO_2, CRYOGENIC
CARBON DIOXIDE - CO_2, SOLID
Document Number: 001013

PRODUCT USE: For general analytical/synthetic chemical uses.

SUPPLIER/MANUFACTURER'S NAME: AIRGAS INC.
ADDRESS: 259 N. Radnor Chester Road
Suite 100
Radnor, PA 19087-5283

BUSINESS PHONE: 1-610-687-5253
EMERGENCY PHONE: 1-800-949-7937
International: 1-423-479-0293

DATE OF PREPARATION: May 20, 1996
DATE OF REVISION: August 3, 2002

2. COMPOSITION and INFORMATION ON INGREDIENTS

CHEMICAL NAME	CAS #	mole %	EXPOSURE LIMITS IN AIR					
			ACGIH		OSHA			
			TLV ppm	STEL ppm	PEL ppm	STEL ppm	IDLH ppm	OTHER ppm
Carbon Dioxide	124-38-9	> 99.8	5000	30,000	5000 10,000 (Vacated 1989 PEL)	30,000 (Vacated 1989 PEL)	40,000	DFG-MAK: 5000 NIOSH REL TWA: 5000 ST: 30000 ppm
Maximum Impurities		< 0.2	None of the trace impurities in this mixture contribute significantly to the hazards associated with the product. All hazard information pertinent to this product has been provided in this Material Safety Data Sheet, per the requirements of the OSHA Hazard Communication Standard (29 CFR 1910.1200) and State equivalent standards.					

NE = Not Established C = Ceiling Limit. See Section 16 for Definitions of Terms Used.

NOTE: All WHMIS required information is included. It is located in appropriate sections based on the ANSI Z400.1-1993 format.

3. HAZARD IDENTIFICATION

Carbon Dioxide Gas and Cryogenic Liquid

EMERGENCY OVERVIEW: Carbon Dioxide is a colorless gas, or a colorless, cryogenic liquid. At low concentrations, both the gas and the liquid are odorless. At higher concentrations Carbon Dioxide will have a sharp, acidic odor. At concentrations between 2 and 10%, Carbon Dioxide can cause nausea, dizziness, headache, mental confusion, increased blood pressure and respiratory rate. If the gas concentration reaches 10% or more, suffocation and death can occur within minutes. Contact with the cold gas can cause freezing of exposed tissue. Moisture in the air could lead to the formation of carbonic acid that can be irritating to the eyes. All forms of Carbon Dioxide are non-combustible. Carbon Dioxide is heavier than air and should not be allowed to accumulate in low lying areas.

CARBON DIOXIDE GAS

HAZARDOUS MATERIAL INFORMATION SYSTEM

HEALTH (BLUE)	1
FLAMMABILITY (RED)	0
REACTIVITY (YELLOW)	0
PROTECTIVE EQUIPMENT	B

EYES	RESPIRATORY	HANDS	BODY
	See Section 8		See Section 8

For routine industrial applications

CARBON DIOXIDE LIQUEFIED

HAZARDOUS MATERIAL INFORMATION SYSTEM

HEALTH (BLUE)	3
FLAMMABILITY (RED)	0
REACTIVITY (YELLOW)	0
PROTECTIVE EQUIPMENT	X

EYES	RESPIRATORY	HANDS	BODY
	See Section 8		See Section 8

For routine industrial applications

See Section 16 for Definition of Ratings

SYMPTOMS OF OVEREXPOSURE BY ROUTE OF EXPOSURE: The most significant route of overexposure for this gas is by inhalation. The following paragraphs describe symptoms of exposure by route of exposure.

INHALATION: Carbon Dioxide is an asphyxiant and a powerful cerebral vasodilator. If the concentration of Carbon Dioxide reaches 10% or more, suffocation can occur rapidly. Inhalation of concentrations between 2 and 10% can cause nausea, dizziness, headache, mental confusion, increased blood pressure and respiratory rate. Carbon Dioxide initially stimulates respiration and then causes respiratory depression. Inhalation of low concentrations (3-5%) have no known permanent harmful effects. Symptoms in humans at various levels of concentration are as follows:

CONCENTRATION	SYMPTOMS OF EXPOSURE
1%:	Slight increase in breathing rate.
2%:	Breathing rate increases to 50% above normal; prolonged exposure can cause headache, tiredness.
3%:	Breathing increases to twice normal rate and becomes labored. Weak narcotic effect. Impaired hearing, headache, increase in blood pressure and pulse rate.
4-5%:	Breathing increases to approximately four times normal rate, symptoms of intoxication become evident and slight choking may be felt.
5-10%:	Characteristic sharp odor noticeable. Very labored breathing, headache, visual impairment and ringing in the ears. Judgment may be impaired, followed by loss of consciousness.
50-100%:	Unconsciousness occurs more rapidly above 10% level. Prolonged exposure to high concentrations may eventually result in death from asphyxiation.

High concentrations of this gas can also cause an oxygen-deficient environment. However, the asphyxiating properties of Carbon Dioxide will be reached before oxygen-deficiency is a factor.

OTHER POTENTIAL HEALTH EFFECTS: Contact of the cold gas with the skin can lead to frostbite or dermatitis (red, cracked, irritated skin), depending upon concentration and duration of exposure. Contact of the cold gas with the eyes can cause pain, redness, burns, and severe exposure could cause blindness. Symptoms of frostbite include change in skin color to white or grayish-yellow. The pain after contact with cold gas can quickly subside. Moisture in the air could lead to the formation of carbonic acid, which can be irritating to the eyes.

HEALTH EFFECTS OR RISKS FROM EXPOSURE: An Explanation in **Lay Terms**. Overexposure to Carbon Dioxide may cause the following health effects:

ACUTE: Inhaling high concentrations of Carbon Dioxide can lead to coma or death. At low concentrations, inhalation of Carbon Dioxide can cause nausea, dizziness, visual disturbances, shaking, headache, mental confusion, sweating, increased heartbeat, and elevated blood pressure and respiratory rate. High concentrations of the gas in air may cause eye irritation or damage.

CHRONIC: Reversible effects on the acid-base balance in the blood, blood pressure, and circulatory system may occur after prolonged exposure to elevated Carbon Dioxide levels.

TARGET ORGANS: Respiratory system, cardiovascular system, eyes.

Carbon Dioxide Solid

EMERGENCY OVERVIEW: Solid Carbon Dioxide (dry ice), is a white, opaque solid which releases colorless, gas. This solid sublimates to gas quickly at standard temperatures and pressures, forming a fog in air. As a result, the main hazards associated with Carbon Dioxide are related to Carbon Dioxide gas formation and the cold temperature of the solid and evolved gas. At concentrations between 2 and 10%, Carbon Dioxide can cause nausea, dizziness, headache, mental confusion, increased blood pressure and respiratory rate. If the gas concentration reaches 10% or more, suffocation and death can occur within minutes. Contact with the solid can cause freezing of exposed tissue. Moisture in the air could lead to the formation of carbonic acid which can be irritating to the eyes. Carbon Dioxide is heavier than air and should not be allowed to accumulate in low lying areas.

SYMPTOMS OF OVEREXPOSURE BY ROUTE OF EXPOSURE: The most significant routes of overexposure for Carbon Dioxide are by inhalation of Carbon Dioxide gas, and skin or eye contact with the solid or gas. Symptoms of such exposure are as follows:

INHALATION: Carbon Dioxide is an asphyxiant and a powerful cerebral vasodilator. If the concentration of Carbon Dioxide reaches 10% or more, suffocation can occur rapidly. Inhalation of concentrations between 2 and 10% can cause nausea, dizziness, headache, mental confusion, increased blood pressure and respiratory rate. Carbon Dioxide initially stimulates respiration and then causes respiratory depression. Inhalation of low concentrations (3-5%) have no known permanent harmful effects. Symptoms in humans at various levels of concentration are as follows:

CONCENTRATION	**SYMPTOMS OF EXPOSURE**
1%:	Slight increase in breathing rate.
2%:	Breathing rate increases to 50% above normal; exposure causes headache, tiredness.
3%:	Breathing increases to twice normal rate and becomes labored. Weak narcotic effect. Impaired hearing, headache, increase in blood pressure and pulse rate.
4-5%:	Breathing increases to approximately four times normal rate, symptoms of intoxication become evident; slight choking may be felt.
5-10%:	Labored breathing, headache, visual impairment, ringing in the ears, impaired judgment, followed by loss of consciousness.
50-100%:	Unconsciousness occurs more rapidly above 10% level. Prolonged exposure to high concentrations may eventually result in death from asphyxiation.

CARBON DIOXIDE SOLID

HAZARDOUS MATERIAL INFORMATION SYSTEM

HEALTH	(BLUE)	2
FLAMMABILITY	(RED)	0
REACTIVITY	(YELLOW)	0
PROTECTIVE EQUIPMENT		B

EYES	RESPIRATORY	HANDS	BODY
	See Section 8		See Section 8

For routine industrial applications

See Section 16 for Definition of Ratings

INHALATION (Continued): High concentrations of this gas can also cause an oxygen-deficient environment. However, the asphyxiating properties of Carbon Dioxide will be reached before oxygen-deficiency is a factor.

OTHER POTENTIAL HEALTH EFFECTS: Contact with solid Carbon Dioxide can cause frostbite to skin, eyes, and other exposed tissue. Contact of the cold gas generated from the solid with the skin can lead to frostbite or dermatitis (red, cracked, irritated skin), depending upon concentration and duration of exposure. Contact of the cold gas with the eyes can cause pain, redness, burns, and severe exposure could cause blindness. Symptoms of frostbite include change in skin color to white or grayish-yellow. The pain after contact with cold gas or solid can quickly subside. Moisture in the air could lead to the formation of carbonic acid, which can be irritating to the eyes.

HEALTH EFFECTS OR RISKS FROM EXPOSURE: An Explanation in **Lay Terms**. Overexposure to Carbon Dioxide may cause the following health effects:

ACUTE: Contact with solid Carbon Dioxide or cold gas can cause frostbite to skin, eyes, and other exposed tissue. Carbon Dioxide gas evolved from the sublimation of the solid is an asphyxiant and a powerful cerebral vasodilator. Inhaling high concentrations of Carbon Dioxide can lead to coma or death. At low concentrations, inhalation of Carbon Dioxide can cause nausea, dizziness, visual disturbances, shaking, headache, mental confusion, sweating, increased heartbeat, and elevated blood pressure and respiratory rate. High concentrations of the gas in air may cause eye irritation or damage.

CHRONIC: There are currently no known adverse health effects associated with chronic exposure to solid Carbon Dioxide or the gas which is generated by sublimation.

TARGET ORGANS: Respiratory system, cardiovascular system, eyes.

PART III *How can I prevent hazardous situations from occurring?*

4. FIRST-AID MEASURES

RESCUERS SHOULD NOT ATTEMPT TO RETRIEVE VICTIMS OF EXPOSURE TO THIS PRODUCT WITHOUT ADEQUATE PERSONAL PROTECTIVE EQUIPMENT. At a minimum, Self-Contained Breathing Apparatus should be worn.

Remove victim(s) to fresh air, as quickly as possible. Trained personnel should administer supplemental oxygen and/or cardio-pulmonary resuscitation, if necessary. Only trained personnel should administer supplemental oxygen.

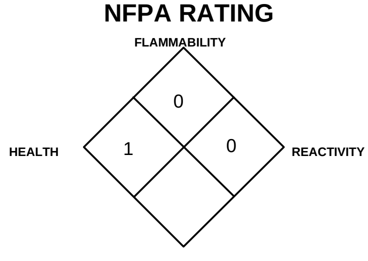
In case of frostbite, place the frostbitten part in warm water. DO NOT USE HOT WATER. If warm water is not available, or is impractical to use, wrap the affected parts gently in blankets. Alternatively, if the fingers or hands are frostbitten, place the affected area in the armpit. Encourage victim to gently exercise the affected part while being warmed. Seek immediate medical attention.

Victim(s) must be taken for medical attention. Rescuers should be taken for medical attention, if necessary. Take copy of label and MSDS to physician or other health professional with victim(s).

5. FIRE-FIGHTING MEASURES

CARBON DIOXIDE GAS

NFPA RATING



CARBON DIOXIDE SOLID

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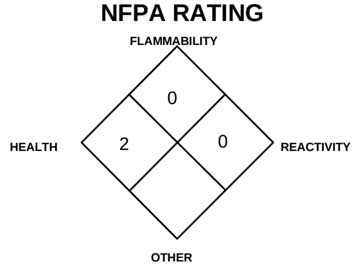
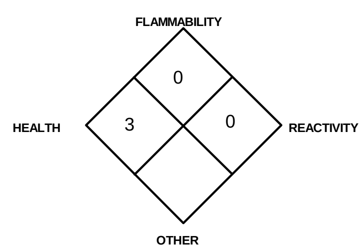


CARBON DIOXIDE LIQUEFIED

NFPA RATING



See Section 16 for Definition of Ratings

FLASH POINT: Not Applicable.

AUTOIGNITION TEMPERATURE: Not Applicable.

FLAMMABLE LIMITS (in air by volume, %): Lower: Not Applicable.
Upper: Not Applicable.

5. FIRE-FIGHTING MEASURES (Continued)

FIRE EXTINGUISHING MATERIALS: Carbon Dioxide is commonly used as an extinguishing agent, and therefore, should not present a problem when trying to control a blaze. Use extinguishing media appropriate for surrounding fire.

UNUSUAL FIRE AND EXPLOSION HAZARDS: Carbon Dioxide does not burn; however, containers, when involved in fire, may rupture or burst in the heat of the fire. Dusts of various reactive metals (e.g. magnesium, zirconium, titanium alloys), are readily ignited and explode in the presence of Carbon Dioxide. Mixtures of solid Carbon Dioxide with sodium and potassium alloys are impact sensitive and explode violently. In the presence of moisture, cesium oxide ignites on contact with Carbon Dioxide. Metal acetylides or hydrides will also ignite or explode.

Explosion Sensitivity to Mechanical Impact: Not sensitive, except as noted above.
Explosion Sensitivity to Static Discharge: Not Sensitive.

SPECIAL FIRE-FIGHTING PROCEDURES: Structural fire-fighters must wear Self-Contained Breathing Apparatus and full protective equipment. Move fire-exposed cylinders if it can be done without risk to firefighters. Otherwise, cool containers with hose stream and protect personnel. Withdraw immediately in case of rising sounds from venting safety device or any discoloration of tanks due to the fire.

6. ACCIDENTAL RELEASE MEASURES

SPILL AND LEAK RESPONSE: Uncontrolled releases should be responded to by trained personnel using pre-planned procedures. Proper protective equipment should be used. In case of a spill, clear the affected area and protect people. Minimum Personal Protective Equipment should be **Level B: protective clothing, mechanically-resistant gloves and Self-Contained Breathing Apparatus**. Locate and seal the source of the leaking gas.

Allow the gas, which is heavier than air, to dissipate. Monitor the surrounding area for Carbon Dioxide and Oxygen levels. Colorimetric tubes are available for Carbon Dioxide. The levels of Carbon Dioxide must be below those listed in Section 2 (Composition and Information on Ingredients) and the atmosphere must have at least 19.5 percent Oxygen before personnel can be allowed in the area without Self-Contained Breathing Apparatus. Attempt to close the main source valve prior to entering the area. If this does not stop the release (or if it is not possible to reach the valve), allow the gas to release in-place or remove it to a safe area and allow the gas to be released there.

RESPONSE TO LIQUID RELEASE: Releasing liquid will immediately turn to dry ice. Clear the affected area and allow the solid to evaporate and the gas to dissipate. Clean up the solid as detailed below. After the gas is formed, follow the instructions provided in the previous paragraph. If the area must be entered by emergency personnel, SCBA, Kevlar gloves, and appropriate foot and leg protection must be worn.

RESPONSE TO SOLID RELEASE: Pick-up and immediately place solid pieces of dry ice in an appropriate, thermally-insulated, vented container. Alternatively, allow the solid to sublimate and the gas that is generated to dissipate.

PART III *How can I prevent hazardous situations from occurring?*

7. HANDLING and STORAGE

WORK PRACTICES AND HYGIENE PRACTICES: As with all chemicals, avoid getting Carbon Dioxide IN YOU. Do not eat or drink while handling chemicals. Be aware of any signs of dizziness, fatigue, or any exposure symptom described in Section 3 (Hazard Identification); exposures to fatal concentrations of Carbon Dioxide could occur without any significant warning symptoms.

STORAGE AND HANDLING PRACTICES: Cylinders should be stored in dry, well-ventilated areas away from sources of heat. Containers of Carbon Dioxide can present significant safety hazards. Store containers away from heavily trafficked areas and emergency exits. Store containers away from process and production areas, away from elevators, building and room exits or main aisles leading to exits. Containers should be stored in dry, well-ventilated areas away from sources of heat, ignition and direct sunlight. Protect containers against physical damage. Isolate from other non-compatible chemicals (refer to Section 10, Stability and Reactivity).

SPECIAL PRECAUTIONS FOR HANDLING GAS CYLINDERS: Protect cylinders against physical damage. Store in cool, dry, well-ventilated, fireproof area, away from flammable materials and corrosive atmospheres. Store away from heat and ignition sources and out of direct sunlight. Do not store near elevators, corridors or loading docks. Do not allow area where cylinders are stored to exceed 52°C (125°F). Use only storage containers and equipment (pipes, valves, fittings to relieve pressure, etc.) designed for the storage of Solid, Gaseous or Liquefied Carbon Dioxide. Do not store containers where they can come into contact with moisture.

SPECIAL PRECAUTIONS FOR HANDLING GAS CYLINDERS (Continued): Cylinders should be stored upright and be firmly secured to prevent falling or being knocked over. Cylinders can be stored in the open, but in such cases, should be protected against extremes of weather and from the dampness of the ground to prevent rusting. Never tamper with pressure relief devices in valves and cylinders. Liquefied Carbon Dioxide must be stored and handled under positive pressure or in a closed system to prevent the infiltration and solidification of air or other gases. The following rules are applicable to situations in which cylinders are being used:

Before Use: Move cylinders with a suitable hand-truck. Do not drag, slide or roll cylinders. Do not drop cylinders or permit them to strike each other. Secure cylinders firmly. Leave the valve protection cap in-place (where provided) until cylinder is ready for use.

During Use: Use designated CGA fittings and other support equipment. Do not use adapters. Do not heat cylinder by any means to increase the discharge rate of the product from the cylinder. Use check valve or trap in discharge line to prevent hazardous backflow into the cylinder. Do not use oils or grease on gas-handling fittings or equipment.

After Use: Close main cylinder valve. Replace valve protection cap (where provided). Mark empty cylinders “EMPTY”.

NOTE: Use only DOT or ASME code containers. In the event of an electrical discharge, Carbon Dioxide gas will produce carbon monoxide and oxygen. Close valve after each use and when empty. Cylinders must not be recharged except by or with the consent of owner.

SPECIAL PRECAUTIONS FOR HANDLING PRESSURIZED CONTAINERS OF LIQUID CARBON DIOXIDE: Cold liquids can present significant safety hazards. Never allow any unprotected part of the body to touch uninsulated pipes or vessels that contain cold fluids. The extremely cold metal of the container will cause moist flesh to stick fast and tear when one attempts to withdraw from it. The following rules are applicable to work situations in which liquid containers are being used.

Check all hoses and transfer equipment before filing them with the liquid. Replace any worn or cut hoses prior to use. Liquid Carbon Dioxide is extremely cold and is under pressure. A leak will result in the formation of “Dry Ice” particles which will be forcibly ejected from the system, possibly injuring the operator. A complete hose failure can result in a large release of Carbon Dioxide and violent movement of the hose and associated equipment, which may cause severe injury or death. Special care must be taken when depressurizing and disconnecting hoses. Releasing the contents of a liquid-filled line to atmospheric pressure may result in the formation of a solid dry ice plug in the line. This plug will prevent further removal of the liquid behind the plug, resulting in either an unexpected, rapid release of Carbon Dioxide as the line warms, or the catastrophic failure of the line as the liquid warms behind the plug. Sufficient vapor pressure must be applied and maintained behind the liquid before opening a discharge valve. This action will prevent the depressurization of the liquid to the point of solid formation before it exits the line.

High-pressure containers for liquid product are equipped with pressure relief devices to control internal pressure. Under normal conditions, these containers will periodically vent small amounts of product. Some metals such as carbon steel may become brittle at low temperatures and will easily fracture. Prevent entrapment of liquid in closed systems or piping without pressure relief devices.

SPECIAL PRECAUTIONS FOR HANDLING OF SOLID CARBON DIOXIDE: Do not handle solid Carbon Dioxide with bare hands. Use heavy gloves or dry ice tongs. Handle blocks of dry ice carefully, as injuries can occur if one is accidentally dropped on the feet. Never store dry ice in a standard refrigerator, cooler, or freezer designed for food storage. Containers of solid Carbon Dioxide should be stored upright and be firmly secured to prevent falling or being knocked-over. Containers should be vented, to prevent the build-up of Carbon Dioxide gas. Carbon Dioxide sublimates at -78.5°C (-109.3°F); containers should be thermally insulated and kept at the lowest possible temperature to maintain the solid and avoid generation of Carbon Dioxide gas. Storage containers and equipment used with Carbon Dioxide should not be located in sub-surface or enclosed areas, unless engineered to maintain a concentration of Carbon dioxide below the TLV (TLV = 5000 ppm in the event of a release. Solid consignment of dry ice in a gas-tight vessel can lead to catastrophic failure of the vessel by over-pressurization. Storage of dry ice should never occur in a gas-tight container.

PROTECTIVE PRACTICES DURING MAINTENANCE OF CONTAMINATED EQUIPMENT: Follow practices indicated in Section 6 (Accidental Release Measures). Make certain application equipment is locked and tagged-out safely. Purge gas handling equipment with inert gas (e.g., Nitrogen) before attempting repairs.

8. EXPOSURE CONTROLS - PERSONAL PROTECTION

VENTILATION AND ENGINEERING CONTROLS: Use with adequate ventilation. Carbon Dioxide accumulates in low-lying areas with limited air movement. Natural or mechanical ventilation should be available in the worker's breathing zone to prevent levels of Carbon Dioxide above exposure limits (see Section 2, Composition and Information on Ingredients). Local exhaust ventilation is preferred, because it prevents dispersion of this gas into the work place by eliminating it at its source. Areas of Carbon Dioxide use should be engineered to remove vapor from the lowest possible level and exhaust vapor to a well-ventilated area or to the outside. Carbon Dioxide levels should be monitored to assure levels are maintained below the TLV. If appropriate, install automatic monitoring equipment to detect the levels of Carbon Dioxide and of Oxygen.

RESPIRATORY PROTECTION: Maintain Carbon Dioxide levels below those listed in Section 2 (Composition and Information on Ingredients) and Oxygen levels above 19.5% in the workplace. Use supplied air respiratory protection if Carbon Dioxide levels are above the IDLH (40,000 ppm) or during emergency response to a release of this product. If respiratory protection is needed, use only protection authorized in the U.S. Federal OSHA Standard (29 CFR 1910.134), applicable U.S. State regulations, or the Canadian CSA Standard Z94.4-93 and applicable standards of Canadian Provinces. Oxygen levels below 19.5% are considered IDLH by OSHA. In such atmospheres, use of a full-facepiece pressure/demand SCBA or a full facepiece, supplied air respirator with auxiliary self-contained air supply is required under OSHA's Respiratory Protection Standard (1910.134-1998). The following are NIOSH respiratory protective equipment recommendations for Carbon Dioxide concentrations in air and are provided for further information:

CONCENTRATION	RESPIRATORY EQUIPMENT
UP TO 40,000 ppm:	Supplied Air Respirator (SAR); or full-facepiece Self-Contained Breathing Apparatus (SCBA).
EMERGENCY OR PLANNED ENTRY INTO UNKNOWN CONCENTRATIONS OR IDLH CONDITIONS:	Positive pressure, full-facepiece SCBA; or positive pressure, full-facepiece SAR with an auxiliary positive pressure SCBA.
ESCAPE:	Escape-type SCBA.

EYE PROTECTION: Splash goggles, face-shields or safety glasses. Face-shields must be worn when using cryogenic Carbon Dioxide. If necessary, refer to U.S. OSHA 29 CFR 1910.133, or Canadian Standards.

HAND PROTECTION: Wear mechanically-resistant gloves when handling cylinders of Carbon Dioxide. Recommended use of low-temperature protective gloves (e.g. insulated polyvinyl chloride or insulated nitrile) when working with containers of Liquefied Carbon Dioxide. Wear thermally insulating gloves when handling Dry Ice.

BODY PROTECTION: Use body protection appropriate for task. Transfer of large quantities under pressure may require protective equipment appropriate to protect employees from splashes of liquefied product, as well provide sufficient insulation from extreme cold.

9. PHYSICAL and CHEMICAL PROPERTIES

GAS DENSITY @ 21°C (70°F) and 1 atm: 0.1144 lb/ft^3 (1.833 kg/m^3)
LIQUID DENSITY @ 21.1°C (70°F) and 838 psig (5778 kPa): 47.35 lb/ft^3 (761.3 kg/m^3)
SOLID DENSITY @ -78.5°C (-109.3°F): 97.59 lb/ft^3 (1569 kg/m^3)
SPECIFIC GRAVITY (gas) @ 21°C (70°F): 1.52
SPECIFIC GRAVITY (solid) @ 0°C (32°F): 1.54
VAPOR PRESSURE (psia): 844.7
SOLUBILITY IN WATER @ 20°C (68°F): 0.90%
ODOR THRESHOLD: Not applicable.
EXPANSION RATIO: Not applicable.
BOILING POINT @ 1 atm (sublimation point): -78.5°C (-109.3°F)
COEFFICIENT WATER/OIL DISTRIBUTION: Not applicable.
EVAPORATION RATE (nBuAc = 1): Not applicable
FREEZING POINT: -56.6°C (-69.9°F)
SPECIFIC VOLUME (ft^3/lb): 8.8
pH @ 1 atm: 3.7 (carbonic acid)
TRIPLE POINT @ 60.4 psig (416 kPa): -56.6°C (-69.9°F)

APPEARANCE AND COLOR: Carbon dioxide is a colorless to opaque, white solid; a colorless gas; or a colorless cryogenic liquid. All forms of Carbon Dioxide are odorless at low concentrations. At high concentrations, Carbon Dioxide will have a sharp, acidic odor.

HOW TO DETECT THIS SUBSTANCE (warning properties): The odor is not a good warning property, as the asphyxiation properties of Carbon Dioxide may present a hazard before the odor at high concentrations is readily detectable. In terms of leak detection for the gas, fittings and joints can be painted with a soap solution to detect leaks, which will be indicated by a bubble formation. In conditions of high humidity, the solid form of Carbon Dioxide may release visible vapors. Colorimetric tubes are available for the detection of Carbon Dioxide.

10. STABILITY and REACTIVITY

STABILITY: Normally stable.
DECOMPOSITION PRODUCTS: Carbon Dioxide gas in an electrical discharge yields carbon monoxide and oxygen. In the presence of moisture, Carbon Dioxide will form carbonic acid.

MATERIALS WITH WHICH SUBSTANCE IS INCOMPATIBLE: Carbon Dioxide will ignite and explode when heated with powdered aluminum, beryllium, cerium alloys, chromium, magnesium-aluminum alloys, manganese, thorium, titanium, and zirconium. In the presence of moisture, Carbon Dioxide will ignite with cesium oxide. Metal acetylides will also ignite and explode on contact with Carbon Dioxide.

HAZARDOUS POLYMERIZATION: Will not occur, however Carbon Dioxide acts to catalyze the polymerization of acrylaldehyde and aziridine.

CONDITIONS TO AVOID: Avoid exposing cylinders of Carbon Dioxide to extremely high temperatures, which could cause the cylinders to rupture or burst. Do not store the solid form of Carbon Dioxide in gas-tight containers, which could also cause over-pressurization and rupture of the container.

PART IV *Is there any other useful information about this material?*

11. TOXICOLOGICAL INFORMATION

TOXICITY DATA: Carbon Dioxide is an asphyxiant gas, which has physiological effects at high concentrations. The following toxicological data are available for Carbon Dioxide.

CARBON DIOXIDE:

LCLo (Inhalation-Human) 9 pph/5 minutes
LCLo (Inhalation-Mammal-species unspecified) 90000 ppm/5 minutes
TCLo (Inhalation-Rat) 10000 ppm/24 hours/days-continuous: Blood: other changes
TCLo (Inhalation-Rat) 6 pph/24 hours: female 10 day(s) after conception: Reproductive: Specific Developmental Abnormalities: musculoskeletal system, cardiovascular (circulatory) system, respiratory system
TCLo (Inhalation-Rat) 6 pph/24 hours: female 10 day(s) after conception: Reproductive: Effects on Newborn: growth statistics (e.g.%, reduced weight gain)

CARBON DIOXIDE (continued):

TCLo (Inhalation-Rabbit) 27,000 ppm/24 hours/30 days-continuous : Behavioral: somnolence (general depressed activity)
TCLo (Inhalation-Rabbit) 13 pph/4 hours: female 9-12 day(s) after conception: Reproductive: Specific Developmental Abnormalities: musculoskeletal system
TCLo (Inhalation-Mouse) 55 pph/2 hours: male 3 day(s) pre-mating: Reproductive: Paternal Effects: spermatogenesis (incl. genetic material, sperm morphology, motility, and count)
TCLo (Inhalation-Mouse) 55 pph/4 hours: male 6 day(s) pre-mating: Reproductive: Fertility: male fertility index (e.g. # males impregnating females per # males exposed to fertile non-pregnant females)

CARBON DIOXIDE (continued):

TCLo (Inhalation-Mouse) 2 pph/8 hours: female 10 day(s) after conception: Reproductive: Fertility: post-implantation mortality (e.g. dead and/or resorbed implants per total number of implants); Specific Developmental Abnormalities: musculoskeletal system

SUSPECTED CANCER AGENT: Carbon Dioxide is not found on the following lists: FEDERAL OSHA Z LIST, NTP, CAL/OSHA, IARC, and therefore is not considered to be, nor suspected to be a cancer-causing agent by these agencies.

IRRITANCY OF PRODUCT: Contact with rapidly expanding gases can cause frostbite and damage to exposed skin and eyes. Due to the formation of carbonic acid, this gas mixture can be slightly irritating to contaminated eyes.

SENSITIZATION OF PRODUCT: Carbon Dioxide is not a sensitizer after prolonged or repeated exposures.

REPRODUCTIVE TOXICITY INFORMATION: Listed below is information concerning the effects of Carbon Dioxide on the human reproductive system.

Mutagenicity: Carbon Dioxide is not expected to cause mutagenic effects in humans.
Embryotoxcity: Carbon Dioxide has not been reported to cause embryotoxic effects; see next paragraph for information.
Teratogenicity: Carbon Dioxide is not expected to cause teratogenic effects in humans. Clinical studies involving test animals exposed to high concentrations of Carbon Dioxide indicate teratogenic effects (e.g., cardiac and skeletal malformations, stillbirths).
Reproductive Toxicity: Carbon Dioxide is not expected to cause adverse reproductive effects in humans. Studies involving test animals exposed to high concentrations of Carbon Dioxide indicate reproductive effects (e.g. changes in testes).

A mutagen is a chemical which causes permanent changes to genetic material (DNA) such that the changes will propagate through generation lines. An embryotoxin is a chemical which causes damage to a developing embryo (i.e. within the first eight weeks of pregnancy in humans), but the damage does not propagate across generational lines. A teratogen is a chemical which causes damage to a developing fetus, but the damage does not propagate across generational lines. A reproductive toxin is any substance which interferes in any way with the reproductive process.

MEDICAL CONDITIONS AGGRAVATED BY EXPOSURE: Disorders involving the “Target Organs” (see Section 3, Hazard Information) may be aggravated by Carbon Dioxide overexposure.

RECOMMENDATIONS TO PHYSICIANS: Treat symptoms and reduce overexposure.

BIOLOGICAL EXPOSURE INDICES (BEIs): Currently, Biological Exposure Indices (BEIs) are not applicable for Carbon Dioxide.

12. ECOLOGICAL INFORMATION

ENVIRONMENTAL STABILITY: Carbon Dioxide occurs naturally in the atmosphere. The gas will be dissipated rapidly in well-ventilated areas. The following environmental data are applicable to Carbon Dioxide.

CARBON DIOXIDE: Food chain concentration potential: None. Biological Oxygen Demand: None

EFFECT OF MATERIAL ON PLANTS or ANIMALS: Any adverse effect on animals would be related to Carbon Dioxide overexposure and oxygen-deficient environments. No adverse effect is anticipated to occur to plant-life, except for frost produced in the presence of rapidly expanding gases.

EFFECT OF CHEMICAL ON AQUATIC LIFE: The following aquatic toxicity data are available for Carbon Dioxide.

CARBON DIOXIDE:
Aquatic toxicity: 100-200 mg/l/no time specified/various organisms/fresh water.
Waterfowl toxicity: Inhalation 5-8%, no effect.

13. DISPOSAL CONSIDERATIONS

PREPARING WASTES FOR DISPOSAL: Product removed from cylinder must be disposed of in accordance with appropriate U.S. Federal, State and local regulations or with regulations of Canada and its Provinces. Return cylinders with residual product to Airgas, Inc. Do not dispose of locally.

14. TRANSPORTATION INFORMATION

THIS MATERIAL IS HAZARDOUS AS DEFINED BY 49 CFR 172.101 BY THE U.S. DEPARTMENT OF TRANSPORTATION.

For Carbon Dioxide Gas:
PROPER SHIPPING NAME: Carbon dioxide
HAZARD CLASS NUMBER and DESCRIPTION: 2.2 (Non-Flammable Gas)
UN IDENTIFICATION NUMBER: UN 1013
PACKING GROUP: Not applicable.
DOT LABEL(S) REQUIRED: Non-Flammable Gas
NORTH AMERICAN EMERGENCY RESPONSE GUIDEBOOK NUMBER (2000): 120

For Carbon Dioxide Liquefied:
PROPER SHIPPING NAME: Carbon dioxide, refrigerated liquid
HAZARD CLASS NUMBER and DESCRIPTION: 2.2 (Non-Flammable Gas)
UN IDENTIFICATION NUMBER: UN 2187
PACKING GROUP: Not applicable.
DOT LABEL(S) REQUIRED: Non-Flammable Gas
NORTH AMERICAN EMERGENCY RESPONSE GUIDEBOOK NUMBER (2000): 120

For Carbon Dioxide, Solid:
PROPER SHIPPING NAME: Carbon dioxide, solid ***or*** Dry ice
HAZARD CLASS NUMBER and DESCRIPTION: 9 (Miscellaneous Dangerous Goods)
UN IDENTIFICATION NUMBER: UN 1845
PACKING GROUP: III
DOT LABEL(S) REQUIRED: None
NORTH AMERICAN EMERGENCY RESPONSE GUIDEBOOK NUMBER (2000): 120

MARINE POLLUTANT: Carbon Dioxide is not classified by the DOT as a Marine Pollutant (as defined by 49 CFR 172.101, Appendix B).

TRANSPORT CANADA TRANSPORTATION OF DANGEROUS GOODS REGULATIONS: THIS MATERIAL IS CONSIDERED AS DANGEROUS GOODS. Use the above information for the preparation of Canadian Shipments.

15. REGULATORY INFORMATION

U.S. SARA REPORTING REQUIREMENTS: Carbon Dioxide is not subject to the reporting requirements of Sections 302, 304 and 313 of Title III of the Superfund Amendments and Reauthorization Act.

U.S. SARA THRESHOLD PLANNING QUANTITY: There are no specific Threshold Planning Quantities for Carbon Dioxide (solid, gaseous or liquid form). The default Federal MSDS submission and inventory requirement filing threshold of 10,000 lbs (4,540 kg) therefore applies, per 40 CFR 370.20.

U.S. CERCLA REPORTABLE QUANTITY (RQ): Not applicable.

CANADIAN DSL/NDSL INVENTORY STATUS: Carbon Dioxide is listed on the DSL Inventory.

U.S. TSCA INVENTORY STATUS: Carbon Dioxide is on the TSCA Inventory.

OTHER U.S. FEDERAL REGULATIONS: Not applicable.

U.S. STATE REGULATORY INFORMATION: Carbon Dioxide is covered under the following specific State regulations:

Alaska - Designated Toxic and Hazardous Substances: Carbon Dioxide.
California - Permissible Exposure Limits for Chemical Contaminants: Carbon Dioxide.
Florida - Substance List: Carbon Dioxide.
Illinois - Toxic Substance List: Carbon Dioxide.
Kansas - Section 302/313 List: No.
Massachusetts - Substance List: Carbon Dioxide.
Michigan - Critical Material Register: No.
Minnesota - List of Hazardous Substances: Carbon Dioxide.
Missouri - Employer Information/Toxic Substance List: Carbon Dioxide.
New Jersey - Right to Know Hazardous Substance List: Carbon Dioxide.
North Dakota - List of Hazardous Chemicals, Reportable Quantities: No.
Pennsylvania - Hazardous Substance List: Carbon Dioxide.
Rhode Island - Hazardous Substance List: Carbon Dioxide.
Texas - Hazardous Substance List: Carbon Dioxide.
West Virginia - Hazardous Substance List: Carbon Dioxide.
Wisconsin - Toxic and Hazardous Substances: Carbon Dioxide.

CALIFORNIA SAFE DRINKING WATER AND TOXIC ENFORCEMENT ACT (PROPOSITION 65): Carbon Dioxide is not on the California Proposition 65 lists.

LABELING: **CARBON DIOXIDE GAS:**

CAUTION:
LIQUID AND GAS UNDER PRESSURE.
CAN CAUSE RAPID SUFFOCATION.
CAN INCREASE RESPIRATION AND HEART RATE.
MAY CAUSE FROSTBITE.
Avoid breathing gas.
Store and use with adequate ventilation.
Do not get liquid in eyes, on skin or clothing.
Cylinder temperature should not exceed 125°F (52°C).
Use equipment rated for cylinder pressure.
Close valve after each use and when empty.
Use in accordance with the Material Safety Data Sheet.

NOTE:
Suck-back into cylinder may cause rupture.
Always use a back flow preventative device in piping.

FIRST-AID:
IF INHALED, remove to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Call a physician.
IN CASE OF FROSTBITE, obtain immediate medial attention.
DO NOT REMOVE THIS PRODUCT LABEL.

CARBON DIOXIDE, LIQUEFIED:

ALWAYS KEEP CONTAINER IN UPRIGHT POSITION.

WARNING:
COLD LIQUID AND GAS UNDER PRESSURE.
CAN INCREASE RESPIRATION AND HEART RATE.
MAY CAUSE FROSTBITE.
Avoid breathing gas.
Store and use with adequate ventilation.
Do not get liquid in eyes, on skin or clothing.
For liquid withdrawal, wear face shield and gloves.
Do not drop. Use hand truck for container movement.
Close valve after each use and when empty.
Use in accordance with the Material Safety Data Sheet.

FIRST-AID:
IF INHALED, remove to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Call a physician.
IN CASE OF FROSTBITE, obtain medical treatment immediately.
DO NOT REMOVE THIS PRODUCT LABEL.

CARBON DIOXIDE, SOLID:

ALWAYS KEEP CONTAINER IN UPRIGHT POSITION.

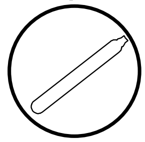
WARNING:
EXTREMELY COLD SOLID THAT SUBLIMATES TO GAS RAPIDLY.
GAS CAN INCREASE RESPIRATION AND HEART RATE.
GAS CAN CAUSE RAPID SUFFOCATION.
CAN CAUSE FROSTBITE.
Avoid breathing gas.
Store and use with adequate ventilation.
Do not get solid in eyes, on skin or clothing.
For handling solid, wear face shield and gloves.
Use in accordance with the Material Safety Data Sheet.

FIRST-AID:
IF INHALED, remove to fresh air. If not breathing, give artificial respiration. If breathing is difficult, give oxygen. Call a physician.

IN CASE OF FROSTBITE, obtain medical treatment immediately.

DO NOT REMOVE THIS PRODUCT LABEL.

CANADIAN WHMIS SYMBOLS: **Class A: Compressed Gas**



16. OTHER INFORMATION

PREPARED BY: Airgas – SAFECOR

> The information contained herein is based on data considered accurate. However, no warranty is expressed or implied regarding the accuracy of these data or the results to be obtained from the use thereof. AIRGAS, Inc. assumes no responsibility for injury to the vendee or third persons proximately caused by the material if reasonable safety procedures are not adhered to as stipulated in the data sheet. Additionally, AIRGAS, Inc. assumes no responsibility for injury to vendee or third persons proximately caused by abnormal use of the material even if reasonable safety procedures are followed. Furthermore, vendee assumes the risk in his use of the material.

DEFINITIONS OF TERMS

A large number of abbreviations and acronyms appear on a MSDS. Some of these which are commonly used include the following:

CAS #: This is the Chemical Abstract Service Number which uniquely identifies each constituent. It is used for computer-related searching.

EXPOSURE LIMITS IN AIR:
ACGIH - American Conference of Governmental Industrial Hygienists, a professional association which establishes exposure limits. **TLV -** Threshold Limit Value - an airborne concentration of a substance which represents conditions under which it is generally believed that nearly all workers may be repeatedly exposed without adverse effect. The duration must be considered, including the 8-hour Time Weighted Average **(TWA)**, the 15-minute Short Term Exposure Limit, and the instantaneous Ceiling Level **(C)**. Skin absorption effects must also be considered.

OSHA - U.S. Occupational Safety and Health Administration.
PEL - Permissible Exposure Limit - This exposure value means exactly the same as a TLV, except that it is enforceable by OSHA. The OSHA Permissible Exposure Limits are based in the 1989 PELs and the June, 1993 Air Contaminants Rule (Federal Register: 58: 35338-35351 and 58: 40191). Both the current PELs and the vacated PELs are indicated. The phrase, “Vacated 1989 PEL,” is placed next to the PEL which was vacated by Court Order.

IDLH - Immediately Dangerous to Life and Health **-** This level represents a concentration from which one can escape within 30-minutes without suffering escape-preventing or permanent injury. **The DFG - MAK** is the Republic of Germany’s Maximum Exposure Level, similar to the U.S. PEL. **NIOSH** is the National Institute of Occupational Safety and Health, which is the research arm of the U.S. **O**ccupational **S**afety and **H**ealth **A**dministration (**OSHA**). NIOSH issues exposure guidelines called **R**ecommended **E**xposure **L**evels (**REL**s). When no exposure guidelines are established, an entry of **NE** is made for reference.

HAZARD RATINGS:
HAZARDOUS MATERIALS IDENTIFICATION SYSTEM: Health Hazard: **0** (minimal acute or chronic exposure hazard); **1** (slight acute or chronic exposure hazard); **2** (moderate acute or significant chronic exposure hazard); **3** (severe acute exposure hazard; onetime overexposure can result in permanent injury and may be fatal); **4** (extreme acute exposure hazard; onetime overexposure can be fatal). Flammability Hazard: **0** (minimal hazard); **1** (materials that require substantial pre-heating before burning); **2** (combustible liquid or solids; liquids with a flash point of 38-93°C [100-200°F]); **3** (Class IB and IC flammable liquids with flash points below 38°C [100°F]); **4** (Class IA flammable liquids with flash points below 23°C [73°F] and boiling points below 38°C [100°F]. Reactivity Hazard: **0** (normally stable); 1 (material that can become unstable at elevated temperatures or which can react slightly with water); **2** (materials that are unstable but do not detonate or which can react violently with water); **3** (materials that can detonate when initiated or which can react explosively with water); **4** (materials that can detonate at normal temperatures or pressures). **PERSONAL PROTECTIVE EQUIPMENT CODES: B:** Gloves and goggles; **C:** Gloves, goggles, rubber apron (appropriate body protection); **D:** Gloves, goggles, faceshield; rubber apron (appropriate body protection);. **X:** Special attention should be given to PPE Selection.

NATIONAL FIRE PROTECTION ASSOCIATION: Health Hazard: **0** (material that on exposure under fire conditions would offer no hazard beyond that of ordinary combustible materials); **1** (materials that on exposure under fire conditions could cause irritation or minor residual injury); **2** (materials that on intense or continued exposure under fire conditions could cause temporary incapacitation or possible residual injury); **3** (materials that can on short exposure could cause serious temporary or residual injury); **4** (materials that under very short exposure could cause death or major residual injury). Flammability Hazard and Reactivity Hazard: Refer to definitions for “Hazardous Materials Identification System”.

FLAMMABILITY LIMITS IN AIR:
Much of the information related to fire and explosion is derived from the National Fire Protection Association (**NFPA**). Flash Point - Minimum temperature at which a liquid gives off sufficient vapors to form an ignitable mixture with air. Autoignition Temperature: The minimum temperature required to initiate combustion in air with no other source of ignition. LEL - the lowest percent of vapor in air, by volume, that will explode or ignite in the presence of an ignition source. UEL - the highest percent of vapor in air, by volume, that will explode or ignite in the presence of an ignition source.

TOXICOLOGICAL INFORMATION:
Possible health hazards as derived from human data, animal studies, or from the results of studies with similar compounds are presented. Definitions of some terms used in this section are: **LD_{50}** - Lethal Dose (solids & liquids) which kills 50% of the exposed animals; **LC_{50}** - Lethal Concentration (gases) which kills 50% of the exposed animals; **ppm** concentration expressed in parts of material per million parts of air or water; **mg/m^3** concentration expressed in weight of substance per volume of air; **mg/kg** quantity of material, by weight, administered to a test subject, based on their body weight in kg. Data from several sources are used to evaluate the cancer-causing potential of the material. The sources are: **IARC** - the International Agency for Research on Cancer; **NTP** - the National Toxicology Program, **RTECS** - the Registry of Toxic Effects of Chemical Substances, **OSHA** and **CAL/OSHA**. IARC and NTP rate chemicals on a scale of decreasing potential to cause human cancer with rankings from 1 to 4. Subrankings (2A, 2B, etc.) are also used. Other measures of toxicity include **TDLo**, the lowest dose to cause a symptom and **TCLo** the lowest concentration to cause a symptom; **TDo**, **LDLo**, and **LDo**, or **TC**, **TCo**, **LCLo**, and **LCo**, the lowest dose (or concentration) to cause lethal or toxic effects. **BEI** - Biological Exposure Indices, represent the levels of determinants which are most likely to be observed in specimens collected from a healthy worker who has been exposed to chemicals to the same extent as a worker with inhalation exposure to the TLV. Ecological Information: EC is the effect concentration in water.

REGULATORY INFORMATION:
This section explains the impact of various laws and regulations on the material. **EPA** is the U.S. Environmental Protection Agency. **WHMIS** is the Canadian Workplace Hazardous Materials Information System. **DOT** and **TC** are the U.S. Department of Transportation and the Transport Canada, respectively. Superfund Amendments and Reauthorization Act **(SARA)**; the Canadian Domestic/Non-Domestic Substances List **(DSL/NDSL)**; the U.S. Toxic Substance Control Act **(TSCA)**; Marine Pollutant status according to the **DOT**; the Comprehensive Environmental Response, Compensation, and Liability Act **(CERCLA or Superfund)**; and various state regulations.

APPENDIX F-1: Groundwater Monitoring Plan for Quaternary and Shallow Pennsylvanian Strata

Groundwater Monitoring Plan for the Quaternary and Shallow Pennsylvanian Strata.
Illinois Industrial Carbon Capture & Sequestration (IL-ICCS) Project
Decatur, Illinois

F1.1. Purpose, Number of Wells, and Well Placement

The purpose of this voluntary (non-regulatory) groundwater monitoring plan is to observe the local spatial and temporal variability of groundwater quality in the Quaternary and Shallow Pennsylvanian strata which are commonly used as private water sources within the application's AoR.

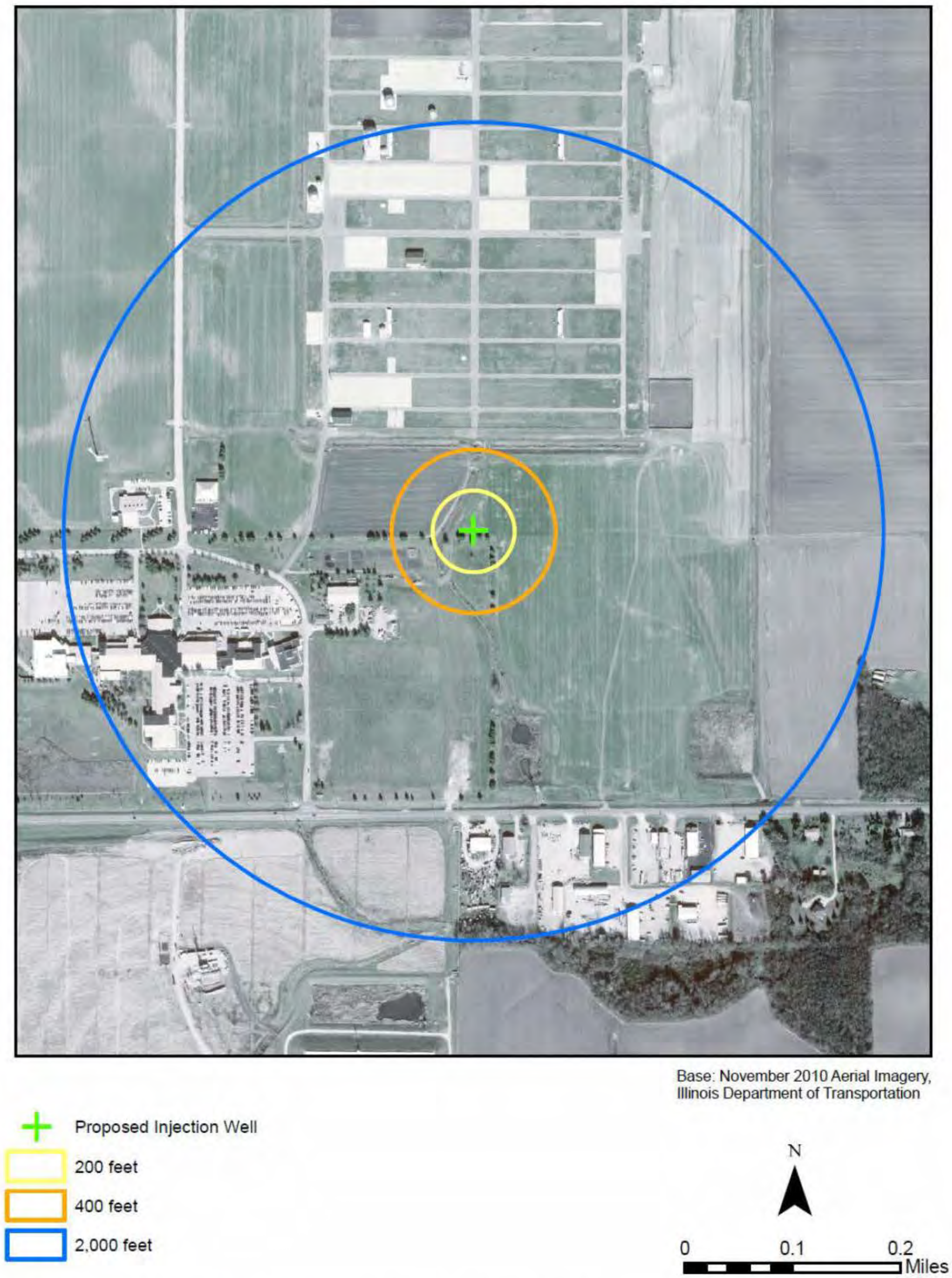
Four (4) monitoring wells are proposed and Figure F1-1 shows the planned locations of the wells. Two wells will be located within 200 feet of the injection well (denoted by the yellow circle), while the other two wells will be located approximately 400 and 2,000 feet from the injection well (denoted by the orange and blue circles, respectively). The exact location of the two closest wells will depend on the final location of the injection well and related infrastructure.

Placement of the two distant wells will be based on the groundwater flow direction and the predicted movement of the CO_2 plume within the Mt. Simon Sandstone. The less dense CO_2 is expected to move upward and updip within the Mt. Simon Sandstone. Regional maps of the Precambrian and the Mt. Simon (e.g., Figures 2-5 through 2-7 in Section 2 of this application) indicate that the updip direction of the Cambrian rocks is northwest.

F1.2. Type of Wells

All groundwater monitoring wells will be installed and eventually abandoned according to Illinois Department of Public Health regulations. During drilling, representative cores will be collected at selected monitoring well locations and archived at the Illinois State Geological Survey. Field descriptions of the cores will be taken and the desired monitoring interval identified. Monitoring wells will be constructed with 2-inch PVC or similar suitable materials using threaded connections. Slotted well screen (e.g., 0.010 inch slot or similar as appropriately sized for formation and sand pack conditions) will be used. The screened interval will have a sand pack of appropriate thickness based on the monitoring interval identified from core samples. Bentonite will be used as the annular fill above the sand pack to near land surface. Concrete and a well protector will be placed at the surface. The locations and elevations of the monitoring wells will be determined by standard land surveying methods based on at least one local benchmark. After well construction and prior to implementing the sampling schedule, all wells will be developed with an inertial-lift pump, electric centrifugal submersible pump, positive air displacement pump, or similar equipment.

Figure F1-1. Approximate IL-ICCS Injection Site Showing Shallow Groundwater Monitoring Target Areas.



IL-ICCS Site, Decatur, IL, showing proposed injection well and distance radii, in feet, from proposed well.

To ensure sample integrity and reduce the introduction of atmospheric CO_2 into the groundwater monitoring wells during sampling, dedicated pumps will be installed. After assembly, the pumps, tubing, and any other downhole accessories will be rinsed with deionized water and placed in plastic bags until deployment. During pump deployment and storage, care will be taken to ensure that equipment to be used inside the monitoring wells remains clean and does not come in contact with potentially contaminating materials.

F1.3. Initiation, Frequency and Duration of Monitoring

After installation of the monitoring wells, pre-injection sampling will be initiated after sufficient well development has occurred to remove as much visible turbidity from the produced water as is practical. After well development, sampling will be conducted at least quarterly and continue through the injection operational period. During the injection period, the sample frequency may be maintained or adjusted (i.e., increased or decreased) based on operational parameters and sample analysis results. Sampling will continue through the first year of the post-injection period, after which, sampling frequency may be greatly reduced (e.g., annually).

F1.4. Sampling Parameters, Sampling Methods, and Analytical Methods

We propose to analyze shallow groundwater samples for the following:

Field Parameters:

- pH
- Specific Conductance
- Temperature
- Dissolved Oxygen

Indicator Parameters:

- Alkalinity
- Bromide
- Calcium
- Chloride
- Sodium
- Total CO_2

All indicator parameters of interest are inorganic and have been selected based on known chemical reactions of CO_2 in aqueous media. These parameters are expected to be key indicators in determining whether injected CO_2 has or has not impacted groundwater quality either 1) directly by introduction of CO_2 into shallow groundwater or 2) indirectly by CO_2-induced migration of groundwater with differing chemical compositions (e.g., brine) into shallow groundwater. As with the sample frequency, the permit holder may revise the list of analytes at any time for this voluntary monitoring based on the consistency of operational parameters and groundwater chemistry results obtained from the wells.

Sample Containers

All sample bottles will be new. Sample bottles and bags for analytes will be used as received from the vendor or contract analytical laboratory or cleaned prior to use as appropriate for the analyte of interest.

Well Purging and Sampling

Static water levels in each well will be determined using an electronic water level indicator before any purging or sampling activities. Dedicated pumps (e.g., bladder pumps) will be installed in each monitoring well to minimize potential cross contamination between wells.

Groundwater pH, temperature, specific conductance, and dissolved oxygen will be monitored in the field using portable probes and a flow-through cell consistent with standard methods (e.g., APHA, 2005) given sufficient flow rates and volumes. Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions. When a flow-through cell is used, field parameters will be continuously monitored and will be considered stable when three successive measurements made three minutes apart meet the criteria listed in Table F1-1. It is anticipated that purging will primarily be conducted based on stabilization of the field parameters using a low-flow method. However, conditions (e.g., low well productivity) may require the use of other methods consistent with ASTM D6452-99 (2005) or Puls and Barcelona (1996). If a flow through cell is not used, field parameters will be measured in grab samples.

Table F1-1. Stabilization criteria of water quality parameters during groundwater monitoring well purging

FIELD PARAMETER	STABILIZATION CRITERIA
pH	+ / - 0.2 units
Temperature	+ / - 1° C
Specific Conductance	+ / - 3% of reading in µS/cm
Dissolved Oxygen	+ / - 10% of reading or 0.3 mg/L whichever is greater

Samples will be filtered through 0.45 µm flow-through filters as appropriate and consistent with ASTM D6564-00. Prior to sample collection, filters will be purged with a minimum of 100 milliliters of well water (or more if required by the filter manufacturer). For alkalinity and total CO_2 samples, efforts will be made to minimize exposure to the atmosphere during filtration, collection in sample containers, and analysis. Sample preservation techniques (Table F1-2) will be consistent with those described in US EPA (1974), American Public Health Association (APHA, 2005), Wood (1976), and ASTM Method D6517-00 (2005). After collection, samples will be placed in ice chests in the field and maintained thereafter at approximately 4° C until analysis.

Table F1-2. Sample preservation and containers

ANALYTE	PRESERVATION[1]	HOLDING TIME[1]	CONTAINER[1]	METHOD
Alkalinity	Filtration, 4° C	In field, 14 days	HDPE bottle	EPA 310.1 APHA[2] 2320
Dissolved Anions: Bromide, Chloride	Filtration, 4° C	28 days	HDPE bottle	EPA 300.0 APHA 4110B
Dissolved Metals: Calcium, Sodium	Filtration, 4° C, HNO_3 < pH 2	6 months	HDPE bottle	EPA 200.8 APHA 3120B
Total CO_2	Filtration, 4° C	14 days	HDPE bottle	APHA 4500-CO_2D Orion, 1990 or ASTM D513-06

Note 1: USEPA, Methods for Chemical Analysis of Water and Wastes, EPA-600/4-79-020

Note 2: American Public Health Association, Standard Methods for the Examination of Water and Wastewater

Sample Analysis

Anion concentrations will be determined by ion chromatography (O'Dell et al., 1984, EPA Method 300.0), and cation concentrations will be determined by inductively coupled plasma (ICP) spectrophotometry, (e.g., EPA Method 200.8; APHA, 2005). Alkalinity will be determined using APHA Method 2320. Total CO_2 concentrations will be determined preferentially by coulometry per ASTM D513-06 or alternatively by other methods (e.g., Orion, 1990; APHA, 2005).

Quality Assurance/Quality Control (QA/QC)

Field quality assurance will primarily include periodic field duplicates and field blanks. One field duplicate and one field blank will be used per sampling event. Additional field QA/QC measures will be implemented according to ASTM Method D7069-04 (2004) as needed based on data analysis of historical results and laboratory performance during the monitoring program.

Sample Chain of Custody

All sample bottles will be labeled with durable labels and indelible markings. A unique sample identification number, sampling date, and analyte(s) will be recorded on the sample bottles as well as sampling records written for each well. Sampling records (e.g., a field logbook, individual well sampling sheet) will indicate the sampling personnel, date, time, sample location/well, unique sample identification number, collection procedure, measured field parameters, and additional comments as needed.

A chain-of-custody record shall be completed and accompany every sample or group of samples collected during an individual sampling event to track sample custody. This record should include: sampler name(s), their affiliation, address, phone number, project identification and project location, sample(s) identification number(s), sampling date and time, signature of person(s) involved in chain-of-custody possession, and remarks regarding sample(s). Where appropriate, ASTM Method D6911-03 (2003) will be followed for packaging and shipping of samples. Immediately upon sample collection, containers shall be placed in an insulated cooler and cooled to 4 degrees Celsius. Samples will either be shipped or hand delivered. Shipment priority will be determined by the holding times or need to expedite sample analysis. Upon receipt at the laboratory, the samples will be accepted and tracked by the laboratory from arrival through completed analysis.

<u>Groundwater Quality Evaluation</u>
Data validation will include the review of the concentration units, sample holding times, and the review of duplicate, blank and other appropriate QA/QC results. All groundwater quality results will be entered into a database or spreadsheet with periodic data review and analysis. Analytical results will be kept on file by the permit holder for the duration of the project, and will be provided to the agency if requested. Analytical data will be evaluated in graphical and tabular formats as appropriate to characterize general groundwater quality and identify intrawell variability with time.

F1.5. References

APHA, 2005, *Standard methods for the examination of water and wastewater (21st edition),* American Public Health Association, Washington, DC.

ASTM, 2010, Method D7069-04 (reapproved 2010), *Standard guide for field quality assurance in a ground-water sampling event*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2010, Method D6911-03 (reapproved 2010), *Standard guide for packaging and shipping environmental samples for laboratory analysis*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6517-00 (reapproved 2005), *Standard guide for field preservation of ground-water samples*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6564-00 (reapproved 2005), *Standard guide for field filtration of ground-water samples*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6452-99 (reapproved 2005), *Standard Guide for Purging Methods for Wells Used for Ground-Water Quality Investigations*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2002, Method D513-02, *Standard test methods for total and dissolved carbon dioxide in water*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2002, Method D6771-02, *Standard guide for low-flow purging and sampling for wells and devices used for ground-water quality investigations*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

Gibb, J.P., R.M. Schuller, and R.A. Griffin, 1981, *Procedures for the collection of representative water quality data from monitoring wells,* Illinois State Geological Survey Cooperative Groundwater Report 7, Champaign, IL, 61 p.

Larson, D.R., B.L. Herzog and T.H. Larson, 2003. *Groundwater geology of DeWitt, Piatt, and Northern Macon Counties, Illinois.* Illinois State Geological Survey Environmental Geology 155, 35 p.

O'Dell, J. W., J. D. Pfaff, M. E. Gales, and G. D. McKee, 1984, *Test Method- The Determination of Inorganic Anions in Water by Ion Chromatography-Method 300*, U.S. Environmental Protection Agency, EPA-600/4-84-017.

Orion Research Inc., 1990, *CO_2 Electrode Instruction Manual*, Orion Research Inc., 36 p.

Puls, R.W., and M.J. Barcelona, 1996, *Low-Flow (Minimal Drawdown) Ground-Water Sampling Procedures*. U.S. Environmental Protection Agency, EPA-540/S-95/504.

US EPA, 2009, *Statistical analysis of groundwater monitoring data at RCRA facilities – Unified Guidance*, US EPA, Office of Solid Waste, Washington, DC.

US EPA, 1974, *Methods for chemical analysis of water and wastes,* US EPA Cincinnati, OH, EPA-625-/6-74-003a.

Wood, W. W., 1976, *Guidelines for collection and field analysis of groundwater samples for selected unstable constituents*, In U.S. Geological Survey, Techniques for Water Resources Investigations, Chapter D-2, 24 p.

APPENDIX F-2: Groundwater Monitoring Plan for the St. Peter Sandstone (lowermost USDW)

Groundwater Monitoring Plan for the St. Peter Sandstone.
Illinois Industrial Carbon Capture & Sequestration (IL-ICCS) Project
Decatur, Illinois

F2.1. Purpose, Number of Wells, and Well Placement

The purpose of this plan is to monitor the St. Peter Sandstone, the lowermost underground source of drinking water (USDW), for any reservoir changes that may indicate leakage through the confining zone.

Geophysical Monitor #2 (GM#2) well will be used to monitor pressure within the St. Peter Sandstone.

Annual reservoir saturation tool (RST) logs will be performed in GM#2 to monitor for CO_2 saturation within the St. Peter Sandstone. Details about using RST logs for monitoring and identifying the presence of CO_2 is described in section 6A.2.5: Tracking Extent and Pressure of CO_2 Plume.

Annual RST surveys will be performed in Verification Well #2 (VW#2) to monitor for CO_2 saturation within the St. Peter Sandstone.

Annual RST surveys will also be performed in CCS#2 (injection well) to monitor for CO_2 saturation at the injection point and to determine the vertical profile of the CO_2 plume at the well bore.

The results from the RST surveys from all of the wells will be integrated into the reservoir simulation models.

Prior to injection, the operator will use GM#2 to obtain baseline samples of the formation fluid within the St. Peter Sandstone. The samples will be obtained using swabbing techniques and/or a downhole fluid sampler. Analysis of these samples will provide the formation's baseline reservoir fluid profile. The geochemical analysis methods for these samples are further described below.

After initiating injection, no additional direct fluid sampling of the St. Peter Sandstone is planned unless pressure and RST measurements show changes in the reservoir condition that indicate leakage through the confining zone.

F2.2. Sampling Parameters, Sampling Methods, and Analytical Methods

We propose to analyze St. Peter Sandstone groundwater samples for the following:

Field Parameters:

- pH
- Specific Conductance
- Temperature

Indicator Parameters:

- Alkalinity
- Bromide
- Calcium
- Chloride
- Sodium

All indicator parameters of interest are inorganic and have been selected based on known chemical reactions of CO_2 in aqueous media. These parameters are expected to be key indicators in determining whether injected CO_2 has or has not impacted groundwater quality either 1) directly by introduction of CO_2 into the St. Peter Sandstone or 2) indirectly by CO_2-induced migration of groundwater with differing chemical compositions (e.g., brine) into the St. Peter Sandstone.

Sample Containers

All sample bottles will be new. Sample bottles and bags for analytes will be used as received from the vendor or contract analytical laboratory or cleaned prior to use as appropriate for the analyte of interest.

Well Sampling

Groundwater pH, temperature, and specific conductance will be measured in collected samples in the field using portable probes consistent with standard methods (e.g., APHA, 2005). Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions.

Samples will be filtered through 0.45 µm filters as appropriate and consistent with ASTM D6564-00. For alkalinity samples, efforts will be made to minimize exposure to the atmosphere during filtration, collection in sample containers, and analysis. Sample preservation techniques (Table F2-1) will be consistent with those described in US EPA (1974), American Public Health Association (APHA, 2005), Wood (1976), and ASTM Method D6517-00 (2005). After collection, samples will be placed in ice chests in the field and maintained thereafter at approximately 4° C until analysis.

Table F2-1. Sample preservation and containers

ANALYTE	PRESERVATION[1]	HOLDING TIME[1]	CONTAINER[1]	METHOD
Alkalinity	Filtration, 4° C	In field, 14 days	HDPE bottle	EPA 310.1 APHA[2] 2320
Dissolved Anions: Bromide, Chloride	Filtration, 4° C	28 days	HDPE bottle	EPA 300.0 APHA 4110B
Dissolved Metals: Calcium, Sodium	Filtration, 4° C, HNO_3 < pH 2	6 months	HDPE bottle	EPA 200.8 APHA 3120B

Note 1: USEPA, Methods for Chemical Analysis of Water and Wastes, EPA-600/4-79-020
Note 2: American Public Health Association, Standard Methods for the Examination of Water and Wastewater

Sample Analysis

Sample analysis will be performed by a National Environmental Laboratory Accreditation Program (NELAP) accredited laboratory. Anion concentrations will be determined by ion chromatography (e.g. O'Dell et al., 1984, EPA Method 300.0), and cation concentrations will be determined by inductively coupled plasma (ICP) spectrophotometry, (e.g., EPA Method 200.8; APHA, 2005). Alkalinity will be determined using APHA Method 2320.

Quality Assurance/Quality Control (QA/QC)

Field quality assurance will primarily include the use of field duplicates and field blanks. One field duplicate and one field blank will be used per sampling event. Additional field QA/QC measures will be implemented according to ASTM Method D7069-04 (2004) as needed.

Sample Chain of Custody

All sample bottles will be labeled with durable labels and indelible markings. A unique sample identification number, sampling date, and analyte(s) will be recorded on the sample bottles as well as sampling records. Sampling records (e.g., a field logbook, individual well sampling sheet) will indicate the sampling personnel, date, time, sample location/well, unique sample identification number, collection procedure, measured field parameters, and additional comments as needed.

A chain-of-custody record shall be completed and accompany every sample or group of samples collected during an individual sampling event to track sample custody. This record should include: sampler name(s), their affiliation, address, phone number, project identification and project location, sample(s) identification number(s), sampling date and time, signature of person(s) involved in chain-of-custody possession, and remarks regarding sample(s). Where appropriate, ASTM Method D6911-03 (2003) will be followed for packaging and shipping of samples. Immediately upon sample collection, containers shall be placed in an insulated cooler and cooled to 4 degrees Celsius. Samples will either be shipped or hand delivered. Shipment priority will be determined by the holding times or need to expedite sample analysis. Upon receipt at the laboratory, the samples will be accepted and tracked by the laboratory from arrival through completed analysis.

Groundwater Quality Evaluation

Data validation will include the review of the concentration units, sample holding times, and the review of duplicate, blank and other appropriate QA/QC results. All groundwater quality results will be entered into a database or spreadsheet. Copies of analytical data from the NELAP laboratory will be kept on file by the permit holder for the duration of the project. A summary of analytical results from the NELAP laboratory will be prepared to characterize general groundwater quality during pre-injection fluid sampling. That summary will then be available for water quality comparisons if subsequent sampling were conducted during the injection or post-injection periods.

F2.5. References

APHA, 2005, *Standard methods for the examination of water and wastewater (21st edition),* American Public Health Association, Washington, DC.

ASTM, 2010, Method D7069-04 (reapproved 2010), *Standard guide for field quality assurance in a ground-water sampling event*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2010, Method D6911-03 (reapproved 2010), *Standard guide for packaging and shipping environmental samples for laboratory analysis*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6517-00 (reapproved 2005), *Standard guide for field preservation of ground-water samples*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6564-00 (reapproved 2005), *Standard guide for field filtration of ground-water samples*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6452-99 (reapproved 2005), *Standard Guide for Purging Methods for Wells Used for Ground-Water Quality Investigations*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

Gibb, J.P., R.M. Schuller, and R.A. Griffin, 1981, *Procedures for the collection of representative water quality data from monitoring wells,* Illinois State Geological Survey Cooperative Groundwater Report 7, Champaign, IL, 61 p.

Larson, D.R., B.L. Herzog and T.H. Larson, 2003. *Groundwater geology of DeWitt, Piatt, and Northern Macon Counties, Illinois.* Illinois State Geological Survey Environmental Geology 155, 35 p.

O'Dell, J. W., J. D. Pfaff, M. E. Gales, and G. D. McKee, 1984, *Test Method- The Determination of Inorganic Anions in Water by Ion Chromatography-Method 300*, U.S. Environmental Protection Agency, EPA-600/4-84-017.

US EPA, 1974, *Methods for chemical analysis of water and wastes,* US EPA Cincinnati, OH, EPA-625-/6-74-003a.

Wood, W. W., 1976, *Guidelines for collection and field analysis of groundwater samples for selected unstable constituents*, In U.S. Geological Survey, Techniques for Water Resources Investigations, Chapter D-2, 24 p.

APPENDIX F-3: Groundwater Monitoring Plan for Ironton-Galesville (first permeable saline unit above the primary seal)

F3.1. Purpose, Number of Wells, and Well Placement

The purpose of this plan is to monitor the Ironton-Galesville formation, located above the confining zone (Eau Claire formation), for any reservoir changes that may indicate leakage through the confining zone.

Verification Well #1 (VW#1), drilled for the Illinois Basin Decatur Project (IBDP), will be used to monitor pressure within the Ironton-Galesville formation.

Annual reservoir saturation tool (RST) logs will be performed in Verification Well #2 (VW#2) to monitor for CO_2 saturation within the Ironton-Galesville formation. Details about using RST logs for monitoring and identifying the presence of CO_2 is described in section 6A.2.5: Tracking Extent and Pressure of CO_2 Plume.

Annual RST surveys will also be performed in CCS#2 (injection well) to monitor for CO_2 saturation at the injection point and to determine the vertical profile of the CO_2 plume at the well bore.

The results from the RST surveys from all of the wells will be integrated into the reservoir simulation models.

Prior to injection, the operator will use VW#1 to obtain baseline samples of fluid within the Ironton-Galesville formation. The samples will be obtained using a downhole fluid sampling device. Analysis of these samples will provide the formation's baseline reservoir fluid profile. The geochemical analysis methods for these samples are further described below.

After initiating injection, no additional direct fluid sampling of the Ironton-Galesville formation is planned unless pressure and RST measurements show changes in the reservoir condition that indicate leakage through the confining zone.

F3.2. Sampling Parameters, Sampling Methods, and Analytical Methods

We propose to analyze the Ironton Galesville groundwater samples for the following:

Field Parameters:

- pH
- Specific Conductance
- Temperature

Indicator Parameters:

- Alkalinity
- Bromide
- Calcium
- Chloride
- Sodium

All indicator parameters of interest are inorganic and have been selected based on known chemical reactions of CO_2 in aqueous media. These parameters are expected to be key indicators in determining whether injected CO_2 has impacted groundwater quality either 1) directly by introduction of injectate into the Ironton-Galesville formation or 2) indirectly by injectate induced migration of groundwater with differing chemical compositions (e.g., brine) into the Ironton-Galesville formation.

<u>Sample Containers</u>

All sample bottles will be new. Sample bottles and bags for analytes will be used as received from the vendor or contract analytical laboratory or cleaned prior to use as appropriate for the analyte of interest.

<u>Well Sampling</u>

Groundwater pH, temperature, and specific conductance, will be measured in the collected samples using portable probes consistent with standard methods (e.g., APHA, 2005). Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions.

Samples will be filtered through 0.45 µm filters as appropriate and consistent with ASTM D6564-00. For alkalinity samples, efforts will be made to minimize exposure to the atmosphere during filtration, collection in sample containers, and analysis. Sample preservation techniques (Table F3-1) will be consistent with those described in US EPA (1974), American Public Health Association (APHA, 2005), Wood (1976), and ASTM Method D6517-00 (2005). After collection, samples will be placed in ice chests in the field and maintained thereafter at approximately 4° C until analysis.

Table F3-1. Sample preservation and containers

ANALYTE	PRESERVATION[1]	HOLDING TIME[1]	CONTAINER[1]	METHOD
Alkalinity	Filtration, 4° C	In field, 14 days	HDPE bottle	EPA 310.1 APHA[2] 2320
Dissolved Anions: Bromide, Chloride	Filtration, 4° C	28 days	HDPE bottle	EPA 300.0 APHA 4110B
Dissolved Metals: Calcium, Sodium	Filtration, 4° C, HNO_3 < pH 2	6 months	HDPE bottle	EPA 200.8 APHA 3120B

Note 1: USEPA, Methods for Chemical Analysis of Water and Wastes, EPA-600/4-79-020
Note 2: American Public Health Association, Standard Methods for the Examination of Water and Wastewater

Sample Analysis

Sample analysis will be performed by a National Environmental Laboratory Accreditation Program (NELAP) accredited laboratory. Anion concentrations will be determined by ion chromatography (e.g. O'Dell et al., 1984, EPA Method 300.0), and cation concentrations will be determined by inductively coupled plasma (ICP) spectrophotometry, (e.g., EPA Method 200.8; APHA, 2005). Alkalinity will be determined using APHA Method 2320.

Quality Assurance/Quality Control (QA/QC)

Field quality assurance will primarily include field duplicates and field blanks. One field duplicate and one field blank will be used per sampling event. Additional field QA/QC measures will be implemented according to ASTM Method D7069-04 (2004) as needed.

Sample Chain of Custody

All sample bottles will be labeled with durable labels and indelible markings. A unique sample identification number, sampling date, and analyte(s) will be recorded on the sample bottles as well as sampling records. Sampling records (e.g., a field logbook, individual well sampling sheet) will indicate the sampling personnel, date, time, sample location/well, unique sample identification number, collection procedure, measured field parameters, and additional comments as needed.

A chain-of-custody record shall be completed and accompany every sample or group of samples collected during an individual sampling event to track sample custody. This record should include: sampler name(s), their affiliation, address, phone number, project identification and project location, sample(s) identification number(s), sampling date and time, signature of person(s) involved in chain-of-custody possession, and remarks regarding sample(s). Where appropriate, ASTM Method D6911-03 (2003) will be followed for packaging and shipping of samples. Immediately upon sample collection, containers shall be placed in an insulated cooler and cooled to 4 degrees Celsius. Samples will either be shipped or hand delivered. Shipment priority will be determined by the holding times or need to expedite sample analysis. Upon receipt at the laboratory, the samples will be accepted and tracked by the laboratory from arrival through completed analysis.

Groundwater Quality Evaluation

Data validation will include the review of the concentration units, sample holding times, and the review of duplicate, blank and other appropriate QA/QC results. All groundwater quality results will be entered into a database or spreadsheet. Copies of analytical data from the NELAP laboratory will be kept on file by the permit holder for the duration of the project. A summary of analytical results from the NELAP laboratory will be prepared to characterize general groundwater quality during pre-injection fluid sampling. That summary will then be available for water quality comparisons if subsequent sampling were conducted during the injection or post-injection periods.

F4.5. References

APHA, 2005, *Standard methods for the examination of water and wastewater (21st edition),* American Public Health Association, Washington, DC.

ASTM, 2010, Method D7069-04 (reapproved 2010), *Standard guide for field quality assurance in a ground-water sampling event*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2010, Method D6911-03 (reapproved 2010), *Standard guide for packaging and shipping environmental samples for laboratory analysis*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6517-00 (reapproved 2005), *Standard guide for field preservation of ground-water samples*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6564-00 (reapproved 2005), *Standard guide for field filtration of ground-water samples*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6452-99 (reapproved 2005), *Standard Guide for Purging Methods for Wells Used for Ground-Water Quality Investigations*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

Gibb, J.P., R.M. Schuller, and R.A. Griffin, 1981, *Procedures for the collection of representative water quality data from monitoring wells,* Illinois State Geological Survey Cooperative Groundwater Report 7, Champaign, IL, 61 p.

O'Dell, J. W., J. D. Pfaff, M. E. Gales, and G. D. McKee, 1984, *Test Method- The Determination of Inorganic Anions in Water by Ion Chromatography-Method 300*, U.S. Environmental Protection Agency, EPA-600/4-84-017.

US EPA, 1974, *Methods for chemical analysis of water and wastes,* US EPA Cincinnati, OH, EPA-625-/6-74-003a.

Wood, W. W., 1976, *Guidelines for collection and field analysis of groundwater samples for selected unstable constituents*, In U.S. Geological Survey, Techniques for Water Resources Investigations, Chapter D-2, 24 p.

APPENDIX F-4: Groundwater Monitoring Plan for the Mt. Simon Sandstone (the injectate storage reservoir)

Groundwater Monitoring Plan for the Mt. Simon Sandstone.
Illinois Industrial Carbon Capture & Sequestration (IL-ICCS) Project
Decatur, Illinois

F4.1. Purpose, Number of Wells, and Well Placement

The purpose of this plan is to monitor the Mt. Simon Sandstone, the injectate storage reservoir, for reservoir changes (pressure, temperature, & saturation) to validate and calibrate the geologic and reservoir simulation models and to track the extent and pressure front of the CO_2 plume.

Verification Well #2 (VW#2) will be used to monitor temperature and pressure within the Mt. Simon Sandstone. The multi-zone monitoring system will be capable of monitoring the temperature and pressure at five (5) selected intervals within the Mt. Simon Sandstone. Details about the temperature and pressure monitoring are described in section 3B.5: Verification Well Completion.

Annual reservoir saturation tool (RST) logs will be performed in VW#2 to monitor for CO_2 saturation within the Mt. Simon Sandstone. Details about using RST logs for monitoring and identifying the presence of CO_2 is described in section 6A.2.5: Tracking Extent and Pressure of CO_2 Plume.

Annual RST surveys will also be performed in CCS#2 (injection well) to monitor for CO_2 saturation at the injection point and to determine the vertical profile of the CO_2 plume at the well bore.

The results from the RST surveys from all of the wells will be integrated into the reservoir simulation models.

Prior to injection, the operator will use VW#2 to obtain baseline samples of formation fluid at the five (5) planned monitoring intervals within the Mt. Simon Sandstone. The samples will be obtained using swabbing techniques and/or a downhole fluid sampler. Analysis of these samples will provide the formation's baseline reservoir fluid profile. The geochemical analysis methods for these samples are further described below.

After initiating injection, no additional direct fluid sampling of the Mt. Simon Sandstone is planned unless temperature, pressure and RST measurements show changes in the upper Mt. Simon reservoir conditions that would indicate a higher risk potential for leakage through the confining zone.

F4.2. Sampling Parameters, Sampling Methods, and Analytical Methods

We propose to analyze Mt. Simon Sandstone groundwater samples for the following:

Field Parameters:
- pH
- Specific Conductance
- Temperature

Indicator Parameters:
- Alkalinity
- Bromide
- Calcium
- Chloride
- Sodium

All indicator parameters of interest are inorganic and have been selected based on known chemical reactions of CO_2 in aqueous media. These parameters will be key indicators in determining how the injected CO_2 has altered the reservoir's fluid quality.

Sample Containers

All sample bottles will be new. Sample bottles and bags for analytes will be used as received from the vendor or contract analytical laboratory or cleaned prior to use as appropriate for the analyte of interest.

Well Sampling

Groundwater pH, temperature, and specific conductance will be measured in the collected samples using portable probes consistent with standard methods (e.g., APHA, 2005). Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions.

Samples will be filtered through 0.45 µm filters as appropriate and consistent with ASTM D6564-00. For alkalinity samples, efforts will be made to minimize exposure to the atmosphere during filtration, collection in sample containers, and analysis. Sample preservation techniques (Table F4-1) will be consistent with those described in US EPA (1974), American Public Health Association (APHA, 2005), Wood (1976), and ASTM Method D6517-00 (2005). After collection, samples will be placed in ice chests in the field and maintained thereafter at approximately 4° C until analysis.

Table F4-1. Sample preservation and containers

ANALYTE	PRESERVATION[1]	HOLDING TIME[1]	CONTAINER[1]	METHOD
Alkalinity	Filtration, 4° C	In field, 14 days	HDPE bottle	EPA 310.1 APHA[2] 2320
Dissolved Anions: Bromide, Chloride	Filtration, 4° C	28 days	HDPE bottle	EPA 300.0 APHA 4110B
Dissolved Metals: Calcium, Sodium	Filtration, 4° C, HNO_3 < pH 2	6 months	HDPE bottle	EPA 200.8 APHA 3120B

Note 1: USEPA, Methods for Chemical Analysis of Water and Wastes, EPA-600/4-79-020
Note 2: American Public Health Association, Standard Methods for the Examination of Water and Wastewater

Sample Analysis

Sample analysis will be performed by a National Environmental Laboratory Accreditation Program (NELAP) accredited laboratory. Anion concentrations will be determined by ion chromatography (e.g. O'Dell et al., 1984, EPA Method 300.0), and cation concentrations will be determined by inductively coupled plasma (ICP) spectrophotometry, (e.g., EPA Method 200.8; APHA, 2005). Alkalinity will be determined using APHA Method 2320.

Quality Assurance/Quality Control (QA/QC)

Field quality assurance will primarily include field duplicates and field blanks. One field duplicate and one field blank will be used per sampling event. Additional field QA/QC measures will be implemented according to ASTM Method D7069-04 (2004) as needed.

Sample Chain of Custody

All sample bottles will be labeled with durable labels and indelible markings. A unique sample identification number, sampling date, and analyte(s) will be recorded on the sample bottles as well as sampling records. Sampling records (e.g., a field logbook, individual well sampling sheet) will indicate the sampling personnel, date, time, sample location/well, unique sample identification number, collection procedure, measured field parameters, and additional comments as needed.

A chain-of-custody record shall be completed and accompany every sample or group of samples collected during an individual sampling event to track sample custody. This record should include: sampler name(s), their affiliation, address, phone number, project identification and project location, sample(s) identification number(s), sampling date and time, signature of person(s) involved in chain-of-custody possession, and remarks regarding sample(s). Where appropriate, ASTM Method D6911-03 (2003) will be followed for packaging and shipping of samples. Immediately upon sample collection, containers shall be placed in an insulated cooler and cooled to 4 degrees Celsius. Samples will either be shipped or hand delivered. Shipment priority will be determined by the holding times or need to expedite sample analysis. Upon receipt at the laboratory, the samples will be accepted and tracked by the laboratory from arrival through completed analysis.

Groundwater Quality Evaluation

Data validation will include the review of the concentration units, sample holding times, and the review of duplicate, blank and other appropriate QA/QC results. All groundwater quality results will be entered into a database or spreadsheet. Copies of analytical data from the NELAP laboratory will be kept on file by the permit holder for the duration of the project. A summary of analytical results from the NELAP laboratory will be prepared to characterize general groundwater quality during pre-injection fluid sampling. That summary will then be available for water quality comparisons if subsequent sampling were conducted during the injection or post-injection periods.

F4.5. References

APHA, 2005, *Standard methods for the examination of water and wastewater (21st edition),* American Public Health Association, Washington, DC.

ASTM, 2010, Method D7069-04 (reapproved 2010), *Standard guide for field quality assurance in a ground-water sampling event*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2010, Method D6911-03 (reapproved 2010), *Standard guide for packaging and shipping environmental samples for laboratory analysis*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6517-00 (reapproved 2005), *Standard guide for field preservation of ground-water samples*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6564-00 (reapproved 2005), *Standard guide for field filtration of ground-water samples*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6452-99 (reapproved 2005), *Standard Guide for Purging Methods for Wells Used for Ground-Water Quality Investigations*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

Gibb, J.P., R.M. Schuller, and R.A. Griffin, 1981, *Procedures for the collection of representative water quality data from monitoring wells,* Illinois State Geological Survey Cooperative Groundwater Report 7, Champaign, IL, 61 p.

O'Dell, J. W., J. D. Pfaff, M. E. Gales, and G. D. McKee, 1984, *Test Method- The Determination of Inorganic Anions in Water by Ion Chromatography-Method 300*, U.S. Environmental Protection Agency, EPA-600/4-84-017.

US EPA, 1974, *Methods for chemical analysis of water and wastes,* US EPA Cincinnati, OH, EPA-625-/6-74-003a.

Wood, W. W., 1976, *Guidelines for collection and field analysis of groundwater samples for selected unstable constituents*, In U.S. Geological Survey, Techniques for Water Resources Investigations, Chapter D-2, 24 p.

APPENDIX N – Plug & Abandonment Plan Supporting Information

OMB No. 2040-0042 Approval Expires 1/31/05

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Archer Daniels Midland Company 4466 Faries Parkway, Decatur, IL 62526	Archer Daniels Midland Company 4466 Faries Parkway, Decatur, IL 62526

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

S

State	County	Permit Number
Illinois	Macon	

Surface Location Description

___ 1/4 of se 1/4 of se 1/4 of nw 1/4 of Section 32 Township 17n Range 3 e

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION

- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells ___

Lease Name: ADM

WELL ACTIVITY

- [ ] CLASS I
- [ ] CLASS II
  - [ ] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Well Number: Class VI CCS#2

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
20	94	350	350	26
13 3/8	61	5300	5300	17 1/2
9 5/8	40	5000	5000	12 1/4
9 5/8	47	2500	2500	12 1/4

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	8.681	8.835					
Depth to Bottom of Tubing or Drill Pipe (ft	7000	4000					
Sacks of Cement To Be Used (each plug)	1333	1443					
Slurry Volume To Be Pumped (cu. ft.)	1480	1703					
Calculated Top of Plug (ft.)	4000	Surf					
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.9	15.9					
Type Cement or Other Material (Class III)	CO2 res	Class A					

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
6700	7050		

Estimated Cost to Plug Wells

Plugs set in 500 ft lifts
Estimated Cost $480,043

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possiblity of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Mark Burau, Decatur Corn Plant Manager		12/05/2012

Paperwork Reduction Act Notice

The public reporting and record keeping burden for this collection of information is estimated to average 19.5 hours annually for operators of Class I wells, 6 hours annually for operators of Class II wells, and 8 hours annually for operators of Class III wells. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.

Please send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Office of Environmental Information, Collection Strategies Division, U.S. Environmental Protection Agency (2822), Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Officer for EPA. Please include the EPA ICR number and OMB control number in any correspondence.

OMB No. 2040-0042 Approval Expires 1/31/05

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Archer Daniels Midland Company 4666 Faries Parkway; Decatur, Il 62526	Archer Daniels Midland Company 4666 Faries Parkway; Decatur, Il 62526

Locate Well and Outline Unit on Section Plat - 640 Acres

N / W / E / S

State	County	Permit Number
Illinois	Macon	

Surface Location Description

___ 1/4 of nw 1/4 of ne 1/4 of nw 1/4 of Section 32 Township 17n Range 3e

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ___ ft. frm (N/S) s Line of quarter section
and ___ ft. from (E/W) e Line of quarter section.

TYPE OF AUTHORIZATION

- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells 1

Lease Name ADM

WELL ACTIVITY

- [ ] CLASS I
- [ ] CLASS II
  - [ ] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Well Number Monitor Well VW#2

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
13 3/8	54.50	363	363	17 1/2
9 5/8	40	5316	5316	12 1/4
5 1/2	17	4961	4961	8 1/2
5 1/2	17 Cr	2259	2259	8 1/2

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	4.892	4.892					
Depth to Bottom of Tubing or Drill Pipe (ft	7030	4000					
Sacks of Cement To Be Used (each plug)	425	442					
Slurry Volume To Be Pumped (cu. ft.)	477	522					
Calculated Top of Plug (ft.)	4000	Surf					
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.9	15.9					
Type Cement or Other Material (Class III)	CO2 res	Class A					

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
7025	7027	6060	6062
6910	6912	5700	5702
6805	6807	Perfs are estimates	
6540	6542	Six zones in Mt. Simon to be	perforated

Estimated Cost to Plug Wells

Plugs to be set in 500 ft lifts
Estimated cost of plugging $363740

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possiblity of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Mark Burau Decatur Corn Plant Manager		12/05/2012

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PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Archer Daniels Midland Company 4666 Faries Parkway; Decatur, Il 62526	Archer Daniels Midland Company 4666 Faries Parkway; Decatur, Il 62526

Locate Well and Outline Unit on Section Plat - 640 Acres

N / W / E / S

State	County	Permit Number
Illinois	Macon	

Surface Location Description

1/4 of sw 1/4 of sw 1/4 of ne 1/4 of Section 32 Township 17n Range 3e

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location ___ ft. frm (N/S) n Line of quarter section
and ___ ft. from (E/W) e Line of quarter section.

TYPE OF AUTHORIZATION

- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells 1

Lease Name ADM

WELL ACTIVITY

- [ ] CLASS I
- [ ] CLASS II
  - [ ] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Well Number Geophysical monitor GM#2

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
9 5/8	40	334	334	12 1/4
4 1/2	17.6	3547	3547	8 1/2

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [ ] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [x] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	4.000						
Depth to Bottom of Tubing or Drill Pipe (ft	3450						
Sacks of Cement To Be Used (each plug)	255						
Slurry Volume To Be Pumped (cu. ft.)	301						
Calculated Top of Plug (ft.)	Surf						
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.9						
Type Cement or Other Material (Class III)	Class A						

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
3540	3550		
Perfs are estimates	base of St. Peter formation		

Estimated Cost to Plug Wells

Plug to set by squeezing cement down casing and filling well with cement
Cost estimate $23135

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibliity of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Mark Burau, Decatur Corn Plant Manager		12/05/2012

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Plugging Cost Estimate CCS# 2 , Injection Well	**Cost Estimate**
Rig time 14 days X $12000	$168,000
Rental work string	$50,000
Misc Rentals BOB etc 14 x $750	$10,500
Fluid handling frac tanks etc	$35,000
Contract services spooling etc	$25,000
Fluid costs kill fluid	$25,000
Cementing costs Franklin estimate	$116,543
Supvervision	$20,000
Mob and De-Mob	$30,000
Total Plugging Estimate	**$480,043**

Plugging Cost Estimate VW#2 , Monitor Well	**Cost Estimate**
Rig time 12 days X $12000	$144,000
Rental work string	$50,000
Misc Rentals BOB etc 14 x $750	$10,500
Fluid handling frac tanks etc	$20,000
Contract services spooling etc	$25,000
Fluid costs kill fluid	$15,000
Cementing costs Franklin estimate	$49,240
Supvervision	$20,000
Mob and De-Mob	$30,000
Total Plugging Estimate	**$363,740**

Plugging Cost Estimate GM#2 , Geophysical Monitor Well	**Cost Estimate**
Rig time 0 days X $0	$0
Rental work string	$0
Misc Rentals BOB etc 14 x $750	$0
Fluid handling frac tanks etc	$2,500
Contract services spooling etc	$0
Fluid costs	$2,500
Cementing costs Franklin estimate	$10,635
Supvervision	$2,500
Misc Sevices	$5,000
Total Plugging Estimate	**$23,135**

FRANKLIN WELL SERVICES INC

1290 State Road 67 N
Vincennes, IN 47591
Phone: (618) 943-4680
FAX: (618) 943-5523

To: Jim Kirksey
For: ADM Project
Subject: Plugging Cost Estimate
Date: December 3, 2012

Jim,

Here is the cost estimate for the plugging of the Injection well, Verification well, and the Geo-Phone well at the ADM Site at Decatur Illinois you requested. Below is the cost estimate based on 4 days at 10 hour on location per day on the Injection and Verification wells and 8 hour on one day on the Geo-phone well.

Injection Well: 4 days
Bottom Plug from 7000 ft to 4000 ft in 500 feet stages
1333 sk 70/30 Class „H"/ Type "C" Poz + 1% C-65 dispersant
Mid Plug: 4000 ft to 2500 ft in 500 ft stages
540 sk Class "A" +1% C-65
Top Plugs: 2500 ft to o Surface in 500 ft stages
903 sk Class "A"
Pumper Mixer
Field Bin
Crew
List Price: $116,543.39 including IL State Sales Tax on Materials
Discounted Price: $104,889.05 if paid within 30 days of invoice date

Verification Well: 4 days
Bottom Plug from 7000 ft to 4000 ft in 500 feet stages
360 sk 70/30 Class „H"/ Type "C" Poz + 1% C-65 dispersant
Mid Plug: 4000 ft to 2500 ft in 500 ft stages
166 sk Class "A" +1% C-65
Top Plugs: 2500 ft to o Surface in 500 ft stages
276 sk Class "A"
Pumper Mixer
Bulk Units
Crew
List Price: $49,240.24 including IL State Sales Tax on Materials
Discounted Price: $44,316.21 if paid within 30 days of invoice date

Geo-phone Well: 1 day
Bull head Plug well down 4 ½” casing
250 sk Class “A”
Pumper Mixer
Bulk Units
Crew
List Price: $11,816.13 including IL State Sales Tax on Materials
Discounted Price: $10,634.51 if paid within 30 days of invoice date

Prices are good for 45 days from the date of this estimate and are estimates based on calculated volumes and estimated time on location, any additional time and materials needed to do the job at time of work will be discounted at the same rate.

If you have any questions please feel free to give me a call and discuss any of the systems. I would like to thank you for allowing Franklin the opportunity to work with you on this project. We do appreciate your continued interest and support of our services.

Sincerely,

Jerry Robinson
Sales Manager
Franklin Well Services, Inc.
618-943-4680 office
618-943-9591 cell
jrobinson@franklinwell.net e-mail
www.franklinwell.net web